(2) Sup. Ct. U.S.

94-1868 MAY 15 1995

No. ——

OFFICE OF THE CLERK

IN THE

Supreme Court of the United States

OCTOBER TERM, 1994

NORTH CAROLINA POWER,
Petitioner,

v.

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION,
Respondent.

Petition for a Writ of Certiorari to the Supreme Court of North Carolina

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APPENDIX TO PETITION FOR A WRIT OF CERTIORARI

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WILSON - EPES PRINTING CO., INC. - 789-0096 - WASHINGTON, D.C. 20001

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Opinion of the Supreme Court of North Carolina, (December 9, 1994)

IN THE SUPREME COURT
OF NORTH CAROLINA

No. 230A93

STATE OF NORTH CAROLINA *ex rel.*
UTILITIES COMMISSION

v.

NORTH CAROLINA POWER

(Filed 9 December 1994)

Justice MITCHELL dissenting in part.

Justice WEBB joins in this dissenting opinion.

FRYE, Justice.

This is an appeal from an order of the North Carolina Utilities Commission (Commission) in a general rate case involving Virginia Electric and Power Company (VEPCO) which operates as North Carolina Power (NC Power) in North Carolina and Virginia Power in Virginia. NC Power is a public utility operating under the laws of North Carolina and is engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation.

Procedurally this case comes to this Court as follows:

On 31 July 1992, NC Power filed an application with the Commission to adjust and increase its rates and charges for electric service to its North Carolina retail customers effective 30 August 1992. The Commission ordered that $1.39 million of the capacity costs paid by NC Power to Ultra Cogen Systems (Ultra Cogen),[1] a cogenerator, be disallowed in calculating approved North Carolina retail rates. Cogeneration involves the simultaneous production of both thermal energy, such as heat or steam, and electric power, usually at an industrial site. By making productive use of the excess heat produced in the generation of thermal energy, cogeneration can produce electricity at a reduced cost. Pursuant to section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), regulations of the Federal Energy Regulatory Commission (FERC) promulgated thereunder, and implementation mechanisms of the states, electric utilities are required to purchase power produced by qualifying cogeneration and small power production facilities and are required to pay their "avoided costs" for the power unless another rate is negotiated.

In the spring and summer of 1986, NC Power was inundated with offers from cogenerators, that were Qualifying Facilities pursuant to federal law, to sell it electricity. In response, in December 1986, NC Power instituted a solicitation process and sent letters to potential sellers. One of NC Power's letters was sent to Ultra Cogen.

On 30 January 1987, in response to this solicitation, NC Power received proposals from Ultra Cogen to sell power from nine projects. Based on numerous factors, including cost, NC Power informed Ultra Cogen in March

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[1] Ultra Cogen Systems has been succeeded in interest by Hadson Power and later by LG&E Development. It will be referred to as Ultra Cogen in this opinion.

1987 that it was rejecting the offer. Between 12 November 1987 and 3 December 1987, Ultra Cogen initiated arbitration proceedings with the Virginia State Corporation Commission (VSCC) seeking to arbitrate NC Power's rejection of its offer. Ultra Cogen requested the VSCC to order NC Power to enter into power purchase agreements. NC Power requested dismissal of the petitions on the ground that the VSCC had expressed its general approval of competitive bidding in a final order issued 29 January 1988. On 26 February 1988, the VSCC rejected NC Power's motion to dismiss and designated Commissioner Thomas Harwood, Jr., of the VSCC as final arbitrator of the dispute. On 30 September 1988, Commissioner Harwood ordered NC Power to execute agreements with Ultra Cogen. This order was adopted by the entire VSCC on 18 November 1988. In compliance with the VSCC's orders, NC Power executed contracts with Ultra Cogen. Additional facts will be discussed where pertinent to the issues raised by NC Power.

The questions presented on this appeal are: (1) whether the Commission's disallowance of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects violates PURPA, N.C.G.S. § 62-133, or the Commerce Clause of the United States Constitution; and (2) whether the Commission's exclusion of $28,000 in officers' salaries violates N.C.G.S. § 62-133. We answer both questions in the negative and affirm the Commission's order.

I.

As stated previously, section 210 of PURPA requires electric utilities to purchase power from qualifying cogeneration and small power production facilties. PURPA directs the Federal Energy Regulatory Commission (FERC) to prescribe rules to encourage cogeneration. These rules must insure that rates for such purchases shall be just and

reasonable to electric consumers and in the public interest, and shall not discriminate against qualifying cogenerators. 16 U.S.C. § 824a-3(b) (1985). PURPA further requires that no rule prescribed for this purpose shall provide a rate which exceeds the incremental cost to the electric utility of alternative electric energy. *Id.* The "incremental cost of alternative electric energy" means the cost to the electric utility to produce or purchase the electric energy which, but for the purchase from such cogenerator or small power producer, the utility would generate or purchase from another source. *Id.* at § 824a-3(d). PURPA also provides that each state regulatory authority shall implement the FERC rule concerning purchases from cogenerators for each electric utility for which it has ratemaking authority. *Id.* at § 824a-3(f).

FERC regulations concerning the arrangements between electric utilities and cogenerators parallel the statutory provisions by requiring that rates for purchases shall be just and reasonable to consumers and in the public interest, and shall not discriminate against cogenerators. 18 C.F.R. § 292.304(a)(1) (1994). The regulations specifically provide that no utility is required to pay more than the avoided costs for purchases. *Id.* at § 292.304(a)(2). "Avoided costs" means the incremental costs which the utility would incur if it supplied the power itself or purchased it from another souurce. *Id.* at § 292.101(b)(6). The regulations further provide that they do not limit the ability of parties to negotiate agreements for rates and terms different from those called for in the regulations. *Id.* at § 292.301(b)(1). For example, a rate for cogeneration purchases may be less than the avoided costs if the state regulatory authority determines that a lower rate is consistent with the regulations and is sufficient to encourage cogeneration and small power production. *Id.* at § 292.304(b)(3). However, in April 1988, FERC held that it is impermissible for states to impose rates exceeding the avoided costs on wholesale purchases

in interstate commerce. *Re Orange and Rockland Utilities, Inc.*, 92 P.U.R.4th 1, 14-15 (1988).[2]

The United States Supreme Court has interpreted PURPA and the FERC regulations to mean that a state regulatory authority, in implementing PURPA and the federal regulations, must apply the avoided-cost rule in the absence of a waiver granted by FERC or a specific contractual agreement setting a price that is lower than the avoided cost. *American Paper Inst. v. American Elec. Power*, 461 U.S. 402, 76 L. Ed. 2d 22 (1983). Therefore, in this case, the VSCC was required to apply the avoided-cost rule in determining wholesale rates pursuant to PURPA and FERC regulations. While both parties in this case are in agreement that the avoided-cost rule is the appropriate method for determining wholesale rates pursuant to PURPA and FERC regulations, they disagree as to what these avoided costs should have been. NC Power contends that when the VSCC set the price it had to pay Ultra Cogen for the wholesale power, the VSCC was implementing federal law and making a determination affecting wholesale power in interstate commerce. Furthermore, when the North Carolina Utilities Commission, in setting North Carolina retail rates, refused to allow NC Power to recover the $1.39 million that the VSCC required NC Power to pay Ultra Cogen, it unlawfully interfered with the VSCC's implementation of federal law. We disagree.

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[2] *Orange and Rockland Utilities* reversed the FERC's earlier position in the preamble to section 210 of PURPA. In the preamble, FERC stated in pertinent part:

> If a State program were to provide that electric utilities must purchase power from [qualifying facilities] at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates, and not on [FERC's] rules.

45 Fed. Reg. 12,214, 12,221 (1980).

NC Power relies on *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 90 L. Ed. 2d 943 (1986), and *Mississippi Power & Light Co. v. Mississippi ex rel. Moore,* 487 U.S. 354, 101 L. Ed. 2d 322 (1988), in support of its arguments that North Carolina is preempted by Virginia's decision. Those cases address the preemptive effect of a rate or apportionment set by FERC for a wholesale transaction subject to regulation under the Federal Power Act. Under FERC regulations, the purchase price for power sold by cogenerators is exempt from regulation by FERC under the relevant provisions of the Federal Power Act, 18 C.F.R. § 292.601(c), and the rate is determined under federal rules implemented by each state for utilities subject to their ratemaking authority. 18 C.F.R. §§ 292.304, 292.401(a). However, states cannot impose purchase rates in excess of avoided costs. *Re Orange and Rockland Utilities, Inc.,* 92 P.U.R.4th 1, 14-15. Therefore, we conclude that the Commission's disallowance of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects does not violate PURPA to the extent it only excludes the amount *above* avoided costs.

We must now compare the VSCC's determination of avoided costs with the Commission's determination of avoided costs.

A. The VSCC's Measure of Avoided Costs

On 27 April 1988, Commissioner Harwood ruled that Ultra Cogen was entitled to receive avoided costs payments determined as of 12 November 1987, the date Ultra Cogen began to file arbitration petitions with the VSCC. The Virginia arbitrator further concluded that the avoided cost payments should be based on NC Power's costs of constructing and operating a gas-fired facility called Chesterfield Unit No. 7, which is intended to be the prototype for any new facility built through the mid-1990's.

In an interim order of 27 May 1988, Commissioner Harwood specified various "key terms and conditions that should be included in a power purchase agreement between the parties." These terms and conditions included the determination that the capacity price for each of the Ultra Cogen projects at issue shall be $341.23 per dependable kilowatt for the first fifteen years of operation and $189.70 for years sixteen through twenty-five. In a final order dated 30 September 1988, he ordered NC Power to execute agreements with Ultra Cogen including these terms. This order was adopted by the entire VSCC on 18 November 1988. In compliance with the VSCC's orders, NC Power executed contracts with Ultra Cogen. NC Power did not exercise its right to appeal the VSCC's order and it did not file the contracts with the North Carolina Utilities Commission. During the test year in this case, NC Power paid Ultra Cogen $2.8 million on a North Carolina retail allocation basis for capacity payments under these contracts.

B. The Commission's Measure of Avoided Costs

On 26 February 1993 the Commission entered an order granting a partial rate increase finding that it was not bound by the actions of the VSCC with regard to the Ultra Cogen contracts and concluding that it was appropriate to reduce operation and maintenance expenses by $1.39 million to reflect the removal of unreasonable capacity costs.

The Commission compared the Ultra Cogen contracts to the results of the 1986 and 1988 competitive bidding solicitations and determined that the rates in the Ultra Cogen contracts exceeded NC Power's avoided costs at the time the arbitration petitions were filed. The 1986 solicitation, which used NC Power's proposed Chesterfield No. 7 as a benchmark, produced average capacity costs of $141 per dependable kilowatt compared to $341 per dependable kilowatt for the Ultra Cogen projects. The

evidence showed that the 1986 projects were expected to operate at a 32.2 percent capacity factor compared to 27.1 percent for the Ultra Cogen projects, thus eliminating any justification for the higher capacity costs on the basis of lower energy costs.

The Commission noted that the Virginia arbitrator himself stated in a February 1990 order that payments for the Doswell projects (from the 1986 solicitation) were based on the avoided costs of Chesterfield No. 7 and were reasonable. The Doswell projects and the Ultra Cogen projects came on-line within a few months of one another (Doswell on 3 May and 10 May 1992 and Ultra Cogen on 22 February, 7 March, and 1 July 1992). The capacity cost for the Doswell projects is $146 per dependable kilowatt, while the capacity cost for the Ultra Cogen projects is $341 per dependable kilowatt. Furthermore, the Ultra Cogen projects' average capacity factor, based on economic dispatch, is approximately one-half that of the Doswell projects' average capacity factor, which indicates the Ultra Cogen projects' energy costs are greater.

The seven projects that were selected in the 1988 solicitation and were operational at the time of the hearing, have an average capacity cost of $171 per dependable kilowatt and a combined capacity factor of 35.9 percent. The Commission used the average capacity costs from the 1988 solicitation as a proxy for what the 1986 solicitation results would have been if the 1986 solicitation had occurred at the time the Ultra Cogen contracts were signed. Using the results of the later solicitation did not prejudice NC Power, but rather allowed it to include $30 per dependable kilowatt (or $240,000) more in rates than if the 1986 results were used.

We conclude that it was not unreasonable for the North Carolina Utilities Commission to use the competitive bidding measure in determining avoided costs, thereby rejecting the measure used by the VSCC. In fact, NC Power argued before the VSCC that competitive bidding should

be the measure used. The North Carolina Utilities Commission carefully reviewed the capacity rate set by the Virginia arbitrator's decision and found that he did not properly take into account other potential sources of power. Thus, the Virginia arbitrator greatly overestimated NC Power's avoided costs. The North Carolina Utilities Commission's exclusion of $1.39 million in expenses for capacity payments for the Ultra Cogen cogeneration projects is nothing more than the disallowance of the amount by which the contract rate exceeded NC Power's avoided costs. Therefore, there is no violation of PURPA.

Next, we address the question of whether the Commission's disallowance of $1.39 million in expenses for capacity payments violates N.C.G.S. § 62-133. Section 62-133(b)(3) provides that the Commission shall determine a utility's "reasonable operating expenses" when setting rates. NC Power contends that the Commission, contrary to North Carolina law, arbitrarily decided that the rates paid Ultra Cogen were too high. NC Power also argues that the Commission, in deciding the reasonableness of operating expenses, must determine whether management has acted prudently. We disagree.

This Court rejected this argument in *State ex rel. Utilities Comm'n v. Carolina Power & Light Co.*, 320 N.C. 1, 358 S.E.2d 35 (1987), reasoning that:

> [A]lthough management prudence may be an important factor considered by the Commission in a general rate case, management prudence *vel non* does not control the Commission's decision as to whether to adjust test period data to reflect abnormalities having a probable impact on the utility's revenues and expenses during the test period, in order that it may set reasonable rates in compliance with N.C.G.S. § 62-133.

Id. at 12, 358 S.E.2d at 41. The conclusion that management imprudence is only one method of demonstrating

that a given expense is unreasonable is also consistent with the standard applied in *State ex rel. Utilities Comm'n v. Intervenor Residents,* 305 N.C. 62, 286 S.E.2d 770 (1982). In *Intervenor Residents,* we held that the Commission must always determine that expenses paid to affiliated companies are reasonable. "If there is an absence of data and information from which either the propriety of incurring the expense or the reasonableness of the cost can readily be determined, the Commission may require the utility to prove [its] propriety and reasonableness by affirmative evidence." *Id.* at 75, 286 S.E.2d at 778.

The findings of the Commission, when supported by competent evidence, are conclusive. *State ex rel. Utilities Comm'n v. Thornburg,* 325 N.C. 484, 385 S.E.2d 463 (1989). In this case, the Commission reviewed the capacity rate set by the Virginia arbitrator and determined that he did not properly take into account other potential sources of power. Thus, his assessment of avoided costs was unreasonably high. The Commission's exclusion of $1.39 million in expenses for capacity payments was merely the disallowance of the amount by which the contract rate exceeded NC Power's avoided costs. Therefore, we conclude that the Commission properly disallowed expenses for unreasonably high payments to Ultra Cogen in accordance with N.C.G.S. § 62-133.

Another issue raised by NC Power is whether the Commission's disallowance of these expenses violates the Commerce Clause of the United States Constitution. Under Article I, Section 8 of the U.S. Constitution, Congress shall have the power "[t]o regulate Commerce . . . among the several States . . . ." In *FERC v. Mississippi,* 456 U.S. 742, 72 L. Ed. 2d 532, *reh'g denied,* 458 U.S. 1131, 73 L. Ed. 2d 1401 (1982), the Court determined that Congress has the power under the Commerce Clause to regulate the relationships between cogenerators and electric utilities in order to protect interstate commerce. Under PURPA, federal law specifically requires each

state to implement federal guidelines for each utility whose rates it regulates. 16 U.S.C. § 824a-3(f). Thus, the Commission is authorized by Congress to act with regard to arrangements between cogenerators and NC Power. The Commission's disallowance of the amount by which the Ultra Cogen contracts exceeded NC Power's avoided costs is consistent with PURPA and the FERC's regulations and constitutes lawful retail ratemaking. The Commission's actions here do not violate the Commerce Clause.

While we recognize that inconsistent determinations of avoided costs by the VSCC and the Commission may burden NC Power, we believe this burden is a necessary consequence of doing business in more than one state. Here, NC Power believed that the capacity rate set by the Virginia arbitrator and ultimately adopted by the VSCC was higher than required by federal law. In fact, NC Power argued before the VSCC that the competitive bidding method should have been used in determining avoided costs. However, instead of appealing the adverse decision of the VSCC to the Virginia courts, NC Power accepted the VSCC decision which required it to pay a rate in excess of avoided costs. NC Power thus accepted the risk that the North Carolina Utilities Commission might not permit it to recover the excess amount from its North Carolina consumers.

II.

Finally, we address the question of whether the Commission's exclusion of $28,000 in officers' salaries violates N.C.G.S. § 62-133. NC Power argues that absent a showing that such salaries are unreasonable or will not actually be incurred, there was no basis for the exclusion of these expenses. We disagree.

One of the critical elements of the ratemaking process is a determination of what expenses are appropriate for inclusion in rates. *State ex rel. Utilities Comm'n v. Eddle-*

man, 320 N.C. 344, 358 S.E.2d 339 (1987), and *State ex rel. Utilities Comm'n v. Public Staff*, 317 N.C. 26, 343 S.E.2d 898 (1986). The Commission argues that it is the policy of the Commission to make executive salary adjustments. *See In re Application of Duke Power Co.*, 75 NCUC Report 298 (1985). In *Application of Duke Power Co.*, the Commission concluded that Duke Power's shareholders shoud bear fifty percent of the overall compensation of those officers whose functions are more closely linked with meeting the demands of the common shareholders. *Id.* The Commission has reached the same conclusion in subsequent rate cases. *See, e.g., In re Application of Duke Power Co.*, 76 NCUC Report 279 (1986), and *In re Application of Carolina Power & Light Co.*, 77 NCUC Report 272 (1987).

In the present case, the Public Staff proposed to remove fifty percent of the salaries of NC Power's President/Chief Executive Officer, the Chairman of the Board of Directors, and the President/Chief Executive Officer of NC Power's sole common stockholder, Dominion Resources, Inc. The Commission concluded that the Public Staff adjustment to exclude fifty percent of the compensation of the three officers in question was appropriate, explaining its reasons for making the executive salary adjustments:

> Witness Maness testified that these three individuals are closely linked to meeting the demands of the Company's common shareholders. All three serve on the VEPCO Board of Directors, as well as the Dominion Resources, Inc. Board of Directors. The Chairman of the VEPCO Board is also the Chairman of the Dominion Resources, Inc. Board, as well as the boards of Dominion Resources, Inc.'s other subsidiaries, Dominion Capital, Dominion Energy, and Dominion Lands. Witness Maness testified that this adjustment is especially appropriate for VEPCO given the nature of Dominion Resources, Inc.'s non-

> regulated business interests. Witness Maness stated that the interests of Dominion Resources, Inc. as they relate to its non-regulated businesses may not always coincide with the interests of VEPCO's retail ratepayers. Witness Maness also testified that the Commission has adopted an adjustment consistent with his approach in each of the seven Duke, CP&L, and VEPCO general rate cases decided since November 1984.

This Court will not disturb the Commission's findings of fact which are supported by competent, material, and substantial evidence in view of the whole record and are not arbitrary or capricious. *State ex rel. Utilities Comm'n v. Thornburg,* 325 N.C. 484, 385 S.E.2d 463 (1989). The authority to regulate the rates of public utilities lies with the Commission and a reviewing court may not modify or reverse its determination merely because the court would have reached a different finding based on the evidence. *State ex rel. Utilities Comm'n v. Eddleman,* 320 N.C. 344, 358 S.E.2d 339 (1987). After reviewing the entire record, we conclude that there is substantial evidence to support the Commission's salary adjustments in this case.

For the foregoing reasons, the Commission's order of 26 February 1993 is affirmed.

AFFIRMED.

Justice MITCHELL dissenting in part.

It is my belief that when the Virgina State Corporation Commission (VSCC) set the price that North Carolina Power (NC Power) must pay Ultra Cogen Systems (Ultra Cogen) for wholesale power, the VSCC was implementing federal law and entering an order affecting wholesale power in interstate commerce. Accordingly, I conclude that when the North Carolina Utilities Commission (NCUC), while setting North Carolina retail rates, refused to allow NC Power to recover the $1.39 million that the VSCC had ordered NC Power to pay Ultra Cogen, it unlawfully interfered with the VSCC's implementation of federal law. Therefore, I dissent from the decision of the majority to the extent that it affirms the NCUC's refusal to allow NC Power to recover the $1.39 million of costs it actually incurred by complying with the VSCC's order requiring it to purchase power from Ultra Cogen.

Under procedures established by federal law, Ultra Cogen applied to the VSCC for an order requiring NC Power to purchase wholesale power from Ultra Cogen and setting the price NC Power would pay for that power. Congress has concluded that wholesale power transactions affect interstate commerce and shall be regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act. As a cogenerator qualifying facility selling wholesale power, Ultra Cogen's sales of wholesale power are controlled by the Federal Public Utility Regulatory Policies Act of 1978 (PURPA). 16 U.S.C. § 828a-3 (1985). By enacting PURPA, Congress has delegated to the states, under mandatory guidelines esablished by the FERC, authority over wholesale transactions involving cogenerators, such as the transaction between Ultra Cogen and NC Power at issue in the present case. As a result, when VSCC set the price NC Power must pay Ultra Cogen for the wholesale power at issue here, the VSCC was implementing federal law and mak-

ing a determination affecting wholesale power in interstate commerce. The VSCC was making a determination which, but for the provisions of PURPA, would have been made exclusively by FERC; that determination was the functional and legal equivalent of an order by the FERC setting the price. For that reason, when the NCUC refused to allow NC Power to recover the $1.39 million in annual capacity costs it had actually incurred as a result of the VSCC order, the NCUC unlawfully interfered with the VSCC's implementation of federal law. In my view, the NCUC's actions were preempted by federal law and must be reversed by this Court.

The Supremacy Clause of the Constitution of the United States subordinates the legislative and administrative acts of the individual states to those of the United States.

> Pre-emption occurs when Congress, in enacting a Federal statute, expresses a clear intent to pre-empt state law when there is outright or actual conflict between Federal and state law, where compliance with both Federal and state law is in effect physically impossible, where there is implicit in Federal law a barrier to state regulation, where Congress has legislated comprehensively, thus occupying an entire field of regulation and leaving no room for the states to supplement Federal law, or where the state law stands as an obstacle to the accomplishment and execution of the full objectives of Congress. Pre-emption may result not only from action taken by Congress itself; a Federal agency acting within the scope of its congressionally delegated authority may pre-empt state regulation.

Louisiana Public Service Comm. v. Federal Communications Comm., 476 U.S. 355, 368-69, 90 L. Ed. 2d 369, 381-82 (1986) (citations omitted). I believe that the doctrine of preemption embodied in the Supremacy Clause

precludes the order entered by the NCUC and affirmed by the majority of this Court in the present case.

PURPA was adopted in 1978 as part of the National Energy Act. *Federal Energy Regulatory Comm. v. Mississippi,* 456 U.S. 743, 745, 72 L. Ed. 2d 532, 537-38 (1982). PURPA represented a response to rapidly fluctuating conditions, including an anticipation of impending shortages of essential non-renewable forms of energy. *Id.* It was intended to advance a national policy of energy conservation. *Id.* Section 210 of Title II of PURPA dealing with cogeneration was part of a broad federal statute that also set standards for retail rates for electric utilities. *Id.* Section 210 was intended to promote the development of qualified cogeneration facilities in order to reduce the demand for traditional fossil fuels. *Id.* at 750, 72 L. Ed. 2d at 541.

PURPA expressly requires the FERC to "prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production." 16 U.S.C. § 824a-3(a) (1985). The FERC is specifically required to promulgate rules requiring electric utilities to "sell electric energy to qualifying cogeneration facilities" and to "purchase electric energy from such facilities." 16 U.S.C. § 824a-3(a)(1)-(2) (1985).

In 1980, pursuant to the requirement of Section 210 (a) of PURPA, the FERC issued a series of regulations further defining federal cogeneration law and policy. Section 292.303(a) of the regulations imposes a federal obligation on electric utilities to purchase power from qualifying facilities; "each electric utility shall purchase, in accordance with [18 C.F.R. § 292.304], any energy and capacity which is made available from a qualifying facility: (1) directly to the electric utility. . . ." 18 C.F.R. § 292.303(a) (1992). Acting under PURPA, the FERC provided that a rate for such purchases satis-

fies the just, reasonable, and public interest requirement for PURPA rates if the rate equals the "avoided costs" of a utility. The FERC required that avoided costs must be derived through a mandatory consideration of specific factors. These factors include the anticipated reliability of the qualifying facility. 18 C.F.R. § 202.304(b)(2), (b)(4), (c) (1992). The FERC has also provided that such rates may be less than avoided cost "if the State regulatory authority . . . determines that a lower rate is consistent with [the just, reasonable, and public interest requirement] and is sufficient to encourage cogeneration." 18 C.F.R. § 292.304(b)(3) (1992).

The FERC regulations also contain additional provisions for establishing rates to be paid to qualifying facilities. They provide that the cogenerator shall, at its option, provide energy or capacity "pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term." 18 C.F.R. § 292.304(d)(2) (1992). If the qualifying facility so decides, "the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either: (i) The avoided costs calculated at the time of delivery; or (ii) The avoided costs calculated at the time the obligation is incurred." *Id.*

The profound effect of PURPA on state authority is demonstrated by the FERC's comments to its 1980 regulations. There, the FERC determined that efficient use of fuels allowed cogeneration facilities to "make a significant contribution to the Nation's effort to conserve its energy resources." 45 Fed. Reg. 12,215 (1980). The FERC further concluded that Section 210 was designed to remove former obstacles to the growth of cogeneration, one of which was that utilities were not generally required to purchase the power produced by a cogenerator at an appropriate rate. *Id.* Under Section 210, each electric utility would be required "to offer to purchase

available electric energy from cogeneration and small production facilities." *Id.*

The FERC also has determined that PURPA requires cooperation between the federal government and the states. Implementation of PURPA is reserved to state regulatory authorities and non-regulated entities. 45 Fed. Reg. 12,216 (1980). In this context, the FERC has determined that "implementation means enforcing the federal obligation on electric utilities to purchase power at avoided cost rates" which expressly requires a determination of "the rate for purchases at a level . . . appropriate to encourage cogeneration." 45 Fed. Reg. 12,221 (1980). Therefore, "[s]tate laws or regulations which would provide rates lower than the Federal standards would fail to provide the requisite encouragement of these technologies, and must yield to Federal law." *Id.* The states' obligation to follow federal rate law is also reflected in the FERC's determination that when a facility "shows that it requires rates for purchases based on full avoided costs to remain viable, or to increase its output, the State regulatory authority . . . is required to establish such rates." 45 Fed. Reg. 12,223 (1980).

It was within the context of the foregoing federal statutes and regulations that the VSCC made its determination that NC Power must purchase wholesale power from Ultra Cogen at the prices the VSCC established. No one has questioned the jurisdiction of the VSCC to hear the dispute or to enter its decision. Ultra Cogen went to the VSCC rather than the NCUC because the wholesale sales at issue were to take place in Virginia. Once the VSCC entered its ruling, the obligation of NC Power to purchase wholesale power from Ultra Cogen and the price of that wholesale power were established by federal law. From that point on, neither the NCUC nor any other state agency was free to establish a different price that NC Power must pay Ultra Cogen for the wholesale power, even though it was to be resold in

North Carolina. Certainly, NC Power was not required to pay Ultra Cogen different prices for the wholesale power purchased depending on the state in which NC Power resold that power. In my view, the NCUC was without authority to indirectly subvert the VSCC's decision by refusing to permit NC Power to recover the amounts it had been forced to pay involuntarily to Ultra Cogen for the power in question by virtue of VSCC's order. Further, I do not share the apparent view of the majority, as expressed in footnote 2 of its opinion, that the failure of NC Power to devote the time and resources necessary to appealing the decision the VSCC had entered over NC Power's strong objections and contentions somehow amounted to acceptance of that decision by NC Power. NC Power was entitled, in my view, to assume that the NCUC would honor the ruling of the VSCC applying federal law.

In *Federal Energy Regulatory Commission v. Mississippi,* the Supreme Court of the United States recognized the preemptive effect of PURPA and rejected a constitutional challenge to Section 210 of PURPA. The Supreme Court recognized that the statute used "state regulatory machinery to advance federal goals," and therefore presented unusual preemption issues. *Federal Energy Regulatory Comm. v. Mississippi,* 456 U.S. at 759, 72 L. Ed. 2d at 546. The Supreme Court expressly stated in this context that "state courts have a unique role in enforcing the body of federal law," and that "state courts were directed to heed the constitutional command that 'the policy of the [F]ederal Act is the prevailing policy in every state . . . and should be respected accordingly in the courts of the State.' " *Id.* at 760, 72 L. Ed. 2d at 547 (quoting *Testa v. Katt,* 330 U.S. 386, 392-93, 91 L. Ed. 2d 967, 972 (1947) and *Mondou v. New York, N.H. & H.R. Co.,* 223 U.S. 1, 57, 56 L. Ed. 327, 349 (1912)). The Supreme Court went on to state that:

> Any other conclusion would allow the States to disregard both the pre-eminent position held by Federal

> law throughout the Nation . . . and the congressional determination that the Federal rights granted by PURPA can appropriately be enforced through state adjudicatory machinery. Such an approach, *Testa* emphasized, "flies in the face of the fact that the States of the Union constitute a nation," and "disregards the purpose and effect of Article IV of the Constitution."

Id. at 760-61, 72 L. Ed. 2d at 548 (citations omitted).

In my view, the decision of the NCUC and the opinion of the majority here conflict with the decision of the Supreme Court of the United States in *Federal Energy Regulatory Commission v. Mississippi*, to the extent that they conclude that the preemption doctrine does not apply and that the order entered by the NCUC was permissible under PURPA. When a state agency purports to carry out the intent of PURPA, it must follow federal law. When the VSCC entered its order requiring NC Power to buy power from Ultra Cogen and setting the price NC Power had to pay for that power, it was enforcing PURPA, the applicable federal law. When the NCUC disregarded the order entered by the VSCC, it prevented the VSCC's lawful order enforcing the controlling federal law established by PURPA and violated the Supremacy Clause. The NCUC assumed total control over the valuation of costs related to PURPA-mandated purchases of electric power, despite the decision by the VSCC implementing PURPA and despite NC Power's clear federal obligation to pay Ultra Cogen the amount set by the VSCC for the power NC Power was required to purchase over its strenuous objections from Ultra Cogen. The error of the NCUC in entering its order is emphasized by its statement in denying more than $1.39 million in annual costs, that "we recognize our [federal] obligation to encourage [qualified cogeneration facilities], but that is not the issue here." I do not believe that the NCUC can so easily avoid the requirements of PURPA by simply as-

serting that they do not apply. I believe that the exclusion of recovery for purchased capacity costs such as those at issue here is directly related to the federal mandate of encouragement of qualifying facilities to produce electric power and conserve the electric resources of this nation.

Because I believe that in determining the amount NC Power must pay Ultra Cogen under PURPA, the VSCC lawfully applied the federal law preempting the field, I believe that the determination of the VSCC had a preemptive effect equivalent to the preemptive effect of FERC orders establishing wholesale rates. That being the case, the VSCC order was binding on the NCUC under the theory of preemption. *See Mississippi Power & Light Co. v. Mississippi ex rel. Moore,* 487 U.S. 354, 101 L. Ed. 2d 322 (1988) (rates mandated by FERC held preemptive); *Nantahala Power & Light Co. v. Thornburg,* 476 U.S. 953, 90 L. Ed. 2d 943 (1986) (same). In my view, the action of the NCUC was preempted by PURPA and by the essentially federal act of the VSCC in establishing the wholesale price that NC Power must pay Ultra Cogen for the power it acquired for resale to its retail consumers. Therefore, I dissent from that part of the decision of the majority holding to the contrary.

Justice WEBB joins in this dissenting opinion.

APPENDIX B

Order of the Supreme Court of North Carolina
(February 15, 1995)

SUPREME COURT OF NORTH CAROLINA

No. 230A93

STATE OF NORTH CAROLINA, *ex rel.*
UTILITIES COMMISSION

v.

NORTH CAROLINA POWER

From NC Utilities Commission
(E-22, SUB 333&5)

ORDER

Upon consideration of the petition filed by Defendant in this matter for rehearing of the decision of this Court pursuant to Rule 31, N.C. Rules of Appellate Procedure, the following order was entered and is hereby certified to the North Carolina Court of Appeals:

> "Denied by order of the Court in conference, this the 13th day of February 1995
>
> /s/ Orr, J.
> For the Court"

WITNESS my hand and the seal of the Supreme Court of North Carolina, this the 15th day of February 1995.

CHRISTIE SPEIR CAMERON
Clerk
Supreme Court of North Carolina

/s/ Marvea J. Francis
MARVEA J. FRANCIS
Assistant Clerk

[SEAL]

APPENDIX C

Order of the North Carolina Utilities Commission (February 26, 1993)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

Docket No. E-22, SUB 333
Docket No. E-22, SUB 335

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

IN THE MATTER OF
REQUEST OF NORTH CAROLINA POWER FOR AUTHORITY TO ADJUST ITS ELECTRIC RATES AND CHARGES

and

APPLICATION OF NORTH CAROLINA POWER PURSUANT TO G.S. 62-133.2 AND NCUC RULE R8-55 RELATING TO FUEL CHARGE ADJUSTMENTS FOR ELECTRIC UTILITIES

ORDER GRANTING PARTIAL RATE INCREASE

BY THE COMMISSION: On July 31, 1992, North Carolina Power (NC Power or the Company) filed an application with the North Carolina Utilities Commission seeking authority to adjust and increase its rates and charges for electric service to its North Carolina retail customers effective on August 30, 1992. NC Power is an

unincorporated division of Virginia Electric and Power Company (Vepco). On August 27, 1992, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, requiring public notice, and scheduling public hearings.

As provided by Commission Rule R8-55, NC Power's fuel adjustment application was due to be filed on September 11, 1992, and a hearing held on November 10, 1992. Docket No. E-22, Sub 335 had been reserved for the 1992 annual fuel charge adjustment proceeding.

On September 4, 1992, NC Power filed a Motion for Consolidation of Hearings in the above-captioned dockets. By its motion, the Company asserted that it intended to file supplemental data updating its testimony in the general rate case with respect to fuel costs and the fuel component of purchased power consistent with the last test period required for its annual fuel charge adjustment proceeding, which was the 12-month period ending June 30, 1992. NC Power therefore proposed that the hearing in its annual fuel charge adjustment proceeding be rescheduled and consolidated with the general rate case hearing scheduled to begin in Raleigh on January 12, 1993.

On September 11, 1992, the Company filed its annual fuel charge adjustment application. On October 5, 1992, the Commission issued an Order consolidating the rate case and fuel clause hearings. In that Order, the Commission provided that the Experience Modification Factor (EMF) shall terminate on December 31, 1992, deferred the implementation of a new EMF until the implementation of base rates in Docket No. E-22, Sub 333, and deferred the implementation of a new fuel cost rider to accommodate the implementation of a new primary fuel component in Docket No. E-22, Sub. 333. The Commission also permitted the Company's September 11, 1992 fuel filing to serve as its fuel-related data in its general

rate case pursuant to G.S. 62-133(c) and Commission Rule R1-17. Finally, the Commission provided for a consolidated public notice of the rate and fuel proceedings.

The Attorney General filed Notices of Intervention on August 25, 1992, in Docket No. E-22, Sub 333 and on January 7, 1993, in Docket No. E-22, Sub 335, pursuant to G.S. 62-20, on behalf of the using and consuming public.

On August 31, 1992, the Carolina Industrial Group for Fair Utility Rates (CIGFUR) filed a Petition to Intervene in Docket No. E-22, Sub 333, which was allowed by Commission Order dated September 2, 1992. CIGFUR also filed a Petition to Intervene in Docket No. E-22, Sub 335, on October 7, 1992, which was allowed by Commission Order dated October 9, 1992.

On October 5, 1992, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to Intervene in Docket No. E-22, Sub 333, which was allowed by the Commission on October 6, 1992. CUCA also filed a Petition to Intervene in Docket No. E-22, Sub, 335, on October 9, 1992, which was allowed by Commission Order dated October 13, 1992.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Ahoskie:	Bill Early
Elizabeth City:	Georgetta Jackson William Pruden Deborah Fox Cavenaugh Keith Fearing
Williamston:	Kenneth Perry Sheila Godard
Roanoke Rapids:	Edwin Akers

The Company presented the testimony and exhibits of the following witnesses: James T. Rhodes, President and Chief Executive Officer of Virginia Electric and Power Company; William E. Avera, a principal in Financial Concepts and Applications, Inc.; Glen B. Ross, Manager-Planning for Virginia Electric and Power Company; Maxwell R. Schools, Jr., Manager-Regulatory Accounting for Virginia Electric and Power Company; and Andrew J. Evans, Director-Rate Design for Virginia Electric and Power Company.

The Company also introduced the affidavits and exhibits of James P. Carney, Director-Financial Analysis for Virginia Electric and Power Company, and Charles R. Goode, III, Director-Regulatory Accounting for Virginia Electric and Power Company.

The Public Staff presented the testimony and exhibits of the following witnesses: John Robert Hinton, Financial Analyst, Economic Research Division of the Public Staff; Kerim Lamar Powell, Electric Engineer, Electric Division of the Public Staff; Benjamin R. Turner, Jr., Electric Engineer, Electric Division of the Public Staff; James S. McLawhorn, Electric Engineer, Electric Division of the Public Staff; Thomas S. Lam, Electric Engineer, Electric Division of the Public Staff; Kelly B. Dietz, Staff Accountant, Accounting Division of the Public Staff and Michael C. Maness, Supervisor, Electric Section, Accounting Division of the Public Staff.

CIGFUR presented the testimony and exhibits of the following witnesses: Nicholas Phillips, Jr., principal in the firm of Drazen-Brubaker & Associates, Inc., and John P. Murphy, Director of Energy Supply for Champion International.

The Company presented the rebuttal testimony of the following witnesses: Maxwell R. Schools, Jr.; Gary L. Edwards, Manager-Capacity Acquisition of Virginia Electric and Power Company; James P. Carney; Andrew J.

Evans; William E. Avera; and John F. Hughes, Jr., Outer Banks District Manager.

Prior to and during the course of the hearings, the parties made various motions and the Commission entered various Orders, all of which are matters of record. Additionally, pursuant to Orders of the Commission or requests of the parties, also of record, certain parties were directed or permitted to submit late-filed exhibits either during or subsequent to the hearings.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearing, the proposed orders and briefs submitted by the parties, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. NC Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. NC Power is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. NC Power is an unincorporated division of Virginia Electric and Power Company and has its office and principal place of business in Richmond, Virginia. Virginia Electric and Power Company is a wholly-owned subsidiary of Dominion Resources, Inc.

2. NC Power is lawfully before this Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133 and for an adjustment in its nuclear and fossil fuel costs pursuant to G.S. 62-133.2.

3. The test period for purposes of the general rate case proceeding (Docket No. E-22, Sub 333) is the 12-month period ended December 31, 1991, adjusted for certain known changes based upon circumstances and events occurring up to the close of the hearing.

4. NC Power, by its general rate case application (Docket No. E-22, Sub 333), sought an increase in its basic rates and charges to its North Carolina retail customers of $21,420,000 consisting of an increase of $22,311,000 in annual basic non-fuel revenues and a decrease in the fuel component of $891,000.

5. The overall quality of electric service provided by NC Power to its North Carolina retail customers is good. The only area of concern is in the Outer Banks, and the Company is taking appropriate action to improve its service there.

6. The Summer/Winter Peak and Average (SWPA) cost allocation method is the most appropriate method for determining the North Carolina retail jurisdictional cost of service.

7. The Summer/Winter Peak and Average (SWPA) cost allocation method is the most appropriate method for determining North Carolina retail customer class cost responsibility.

8. The appropriate level of materials and supplies for use in this proceeding is $13,090,000.

9. The appropriate level of cash working capital investment for use in this proceeding is $(2,458,000).

10. NC Power's reasonable rate base used and useful in providing service to its North Carolina retail customers is $367,831,000, consisting of electric plant in service (including nuclear fuel) of $598,046,000 and materials and supplies of $13,090,000, reduced by accumulated depreciation of $166,889,000, accumulated amortization of nuclear fuel of $36,842,000, accumulated deferred income taxes of $37,101,000, cash working capital of $2,458,000, and other cost-free capital of $15,000.

11. The appropriate level of test year North Carolina jurisdictional sales is 2,521,134 mWh.

12. The appropriate level of unbilled test year sales is 8,795 mWh.

13. The appropriate level of basic rate schedule revenues based on rates in effect as of February 14, 1991, is $134,938,156.

14. The appropriate level of basic revenue related to unbilled sales is $430,599.

15. The appropriate end-of-period level of revenues for load management credits is $(176,117), before reallocation for demand site management (DSM) considerations.

16. The appropriate end-of-period level of revenues related to facilities charges is $408,313.

17. The appropriate level of end-of-period revenues related to miscellaneous service charges is $856,470.

18. The appropriate level of revenue associated with growth, usage, and weather is calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues and test year kWh sales.

19. The mWh adjustments related to weather normalization, customer growth, and increased usage for the 12-month test period through the update period ending September 30, 1992, are (5,308) mWh, (6,447) mWh, and 144,361 mWh, respectively, for a total of 132,606 mWh. These adjustments are appropriate for use in this proceeding.

20. The basic revenue related to weather normalization, customer growth, and increased usage for the test year through the update period ending September 30, 1992, is $6,746,512.

21. The adjusted level of sales for the test year through the update period ending September 30, 1992, is 2,662,535 mWh.

22. The basic revenue related to growth in load management credits for the test period through the update period ending September 30, 1992, is $(6,126).

23. Total rate schedule revenue (excluding fuel revenue) for the test period through the update period ending September 30, 1992, is $142,115,267.

24. For the test period through the update period ending September 30, 1992, total basic adjusted revenue excluding other miscellaneous revenue is $142,683,807 based on the sum of adjusted rate schedule revenue of $142,115,267; less load management credits of $176,117, growth related to load management of $6,126, and allocated DSM cost of $514,000; plus revenue derived from facilities charges of $408,313, plus miscellaneous service revenue of $856,470.

25. The proper level of gross revenue for the Company for the test year (excluding fuel revenue) under present rates and after accounting and pro forma adjustments is $144,377,000.

26. Vepco reported that in 1986 it decided to deal with non-utility generation (NUG) offers by conducting a solicitation because it was receiving NUG capacity offers in amounts greater than its projected needs for the foreseeable future.

27. The Company instituted its solicitation process by sending out a letter on December 23, 1986, to interested developers. The letter was sent to Ultra Cogen Systems, Inc. (Ultra Cogen), at its request on January 13, 1987.

28. The Company sought 700 MW of capacity through its December 1986 solicitation. In response it received bids for 5,083 MW. The Company selected ten projects for negotiation and ultimately signed contracts in June 1987 for seven projects totaling 1,264 MW. Six of these projects are in operation with a dependable capacity of 1,412 MW. The contract for the remaining project has been terminated.

29. In March 1988, Vepco issued a formal Request for Proposals seeking 1,750 MW of capacity. It received bids for 95 projects totalling 14,653 MW. It ultimately signed contracts for 19 projects totalling 2,086 MW. Eleven projects are still active totalling 1,291 MW, seven of which currently are operational with a dependable capacity of 982.4 MW.

30. The Company undertook a solicitation for peaking power in October 1988 from which no contracts were signed. An all source solicitation for 1,100 MW was undertaken in 1989. The 1989 solicitation resulted in 11,000 MW being offered. Contracts were signed for 442 MW and Vepco announced it would build its own 400 MW coal plant. No projects from this solicitation are currently in operation.

31. The Virginia State Corporation Commission (SCC) and the Public Staff have expressed concerns about the Company's capacity planning process, including whether its decisions to buy or build have been based on questionable cost data, its failure to compare its estimated construction costs with each individual NUG project in its winning package, and its bias toward NUG capacity purchases.

32. The contracts the Company has entered into for NUG projects contain a variety of terms regarding how total costs are divided between capacity and energy costs and how capacity costs are structured. The Public Staff has expressed concerns about ratchet arrangements where higher capacity payments are paid in earlier years and lower payments are paid in the final years of the contracts.

33. The Public Staff has not evaluated the reasonableness and appropriateness of indiivdual NUG contracts resulting from the Company's various solicitations. The NUG expenses being allowed in rates as reasonable are being allowed for purposes of this proceeding only.

34. The Hadson projects were originally proposed by Ultra Cogen during the 1986 solicitation and rejected by

Vepco because the price proposed was excessive and Ultra Cogen was unwilling to accept certain terms and conditions.

35. Arbitration proceedings were initiated by Ultra Cogen's filing of eight arbitration petitions with the SCC for nine projects (two of which were in West Virginia) between November 12, 1987, and December 3, 1987, requesting the SCC to order Vepco to enter into power purchase agreements.

36. Ultra Cogen's first petition for arbitration, which was filed on November 12, 1987, involved a proposed cogeneration facility at The Lane Company, Inc. (Lane) in Altavista, Virginia (Case No. PUE870088). The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which is of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result.

37. The Virginia SCC issued a policy statement on competitive bidding on January 29, 1988, finding that PURPA does not require a utility to offer full administratively determined avoided cost to qualifying facilities (QFs) and that avoided costs could be determined through competitive bidding.

38. The SCC's policy statement on competitive bidding also provided that in the evaluation of specific proposals favorable weight should be assigned to the use of Virginia fuels, manpower and other state resources, the benefits to be derived by the industries and communities associated with particular projects, and other identifiable economic and societal benefits to the people of the Commonwealth of Virginia.

39. Vepco requested dismissal of the arbitration petitions on the grounds that the SCC had expressed general approval of bidding in its policy statement of January 29, 1988.

40. On February 26, 1988, one month after the SCC's policy statement on competitive bidding, the SCC issued an Order requiring Vepco to negotiate with Ultra Cogen and naming a Commissioner to serve as arbitrator.

41. Ultra Cogen and Vepco agreed that the number of projects to be considered by the SCC would be reduced to four, within Vepco's territory, with Ultra Cogen being allowed to select the four from five potential projects at a later date.

42. Vepco's position in the arbitration proceedings was that the prices resulting from the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to set the prices in the Ultra Cogen contracts. The arbitrator disagreed.

43. The Virginia arbitrator required the prices for these projects to be based on Vepco's costs of its Chesterfield 7 as those costs were projected on November 12, 1987, the date the first petition for arbitration was filed.

44. Vepco analyzed the projected capacity and energy costs of a unit similar to Chesterfield 7 over a 25-year period.

45. The payments that correspond to the arbitrator's directive were established in the arbitrator's Interim Order dated May 27, 1988, along with other key terms and conditions to be included in a power purchase agreement between the parties. The capacity payments for the Hadson projects were set at $341/kW for the first 15 years.

46. Ultra Cogen's energy prices were established based on the assumption that coal prices would be increasing in the future. Vepco's fuel reports on file with this Commission show that from 1984 through 1987 the

cost of coal decreased and has remained relatively stable ever since.

47. The Award and Final Order issued in the arbitration proceedings on September 30, 1988, recognized that the agreements between the parties reflected negotiations and rulings based on the unique circumstances of those proceedings, including that the projects involved coal-fired facilities in lesser populated areas of the Commonwealth.

48. Vepco did not appeal the SCC arbitration orders to the courts.

49. Ultra Cogen subsequently was purchased by Hadson Power and these projects became known as Hadson Power 11—Southampton, Hadson Power 12—Altavista, and Hadson Power 13—Hopewell (the Hadson projects). Hadson was recently purchased by LG&E Development Corporation. These projects are now owned by a conglomerate of limited and general partners, including subsidiaries of Westmoreland Coal and a Chrysler Capital Corporation subsidiary.

50. The Hadson Power 11—Southampton project came on line on March 7, 1992; the Hadson Power 12—Altavista project on February 22, 1992; and the Hadson Power 13—Hopewell project on July 1, 1992. The fourth project is in default.

51. Vepco is currently obligated to pay $64 million on a system basis for capacity costs under three of the four contracts that Vepco entered into with Ultra Cogen as a result of the arbitration proceedings before the Virginia SCC.

52. Vepco did not file any information with this Commission concerning the arbitration proceeding or the resulting capacity costs associated with the arbitrated projects until this proceeding.

53. Vepco has not filed the contracts for the Hadson projects or otherwise sought Commission approval of the capacity or energy costs of the projects except in its application in this rate case.

54. The average capacity cost of the 1986 projects is $141/kW. If this capacity cost were used to adjust the Hadson projects' capacity costs of $341/kW, $1.63 million of the capacity costs would be unreasonable and subject to disallowance.

55. The average capacity cost of the 1988 projects is $171/kW. If this capacity cost were used to adjust the Hadson projects' capacity costs of $341/kW, $1.39 million of the capacity costs would be unreasonable and subject to disallowance.

56. The same Virginia Commissioner who served as arbitartor in the proceeding involving the Ultra Cogen projects issued an Order in 1990 concerning Doswell Limited Partnership's application for approval of the construction of a 650 MW NUG project. This Order indicated that Doswell's anticipated contractual payments were based upon the avoided costs of Chesterfield 7 and that these contractual payments were considered reasonable. The capacity costs for the Doswell project sought to be recovered in this proceeding are $146/kW.

57. This Commission is not bound by actions of the SCC with regard to the Hadson projects.

58. While the average capacity cost for the 1986 solicitation could be used to adjust the capacity costs for the Hadson projects, the average capacity cost for the operational projects resulting from the 1988 solicitation is more appropriate.

59. It is appropriate to reduce the Company's operation and maintenance expense by $1,390,000 to reflect unreasonable purchased capacity costs.

60. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended in whole or in part to compete with natural gas utilities or w th other energy providers. The amount of these advertising costs to be removed in this case totals $54,000.

61. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended to promote the sale of electricity in a manner inconsistent with the provisions setting forth the allowable types of such advertising in Commission Rules R12-12 and R12-13. The amount of these advertising costs to be removed in this case totals $11,000.

62. It is appropriate to remove from operation and maintenance expense the costs of advertisements which are intended to enhance the Company's image or to achieve other objectives not related to the provision of safe and reliable electric utility service. The amount of these advertising costs to be removed in this case totals $13,000.

63. The Public Staff adjustment to exclude $28,000 from expenses, representing 50% of the North Carolina retail portion of the compensation of the officers most closely linked with meeting the demands of the Company's common stockholder, is reasonable and appropriate for purposes of this proceeding.

64. The Public Staff adjustment to remove $10,000 related to community and government affairs projects and $89,000 of other charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

65. The Public Staff adjustment to increase operation and maintenance expense by $41,000 to reflect common stock issuance costs is reasonable and appropriate for purposes of this proceeding.

66. The level of operation and maintenance expense (other than fuel) under present rates appropriate for use in this proceeding is $75,065,000.

67. It is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 3 loss amortization of $1,306,000 from depreciation and amortization expense. It is also reasonable and appropriate to establish a rate rider of 0.066328¢/kWh, to expire one year from the date of this Order, for the purpose of allowing the Company to recover the remaining unamortized loss.

68. The level of depreciation and amortization expense appropriate for use in this proceeding is $20,606,000.

69. The level of other tax expense present rates appropriate for use in this proceeding is $11,100,000.

70. The Public Staff adjustment of $(4,000) to reflect the use of an average North Carolina state income tax surcharge rate of 1.5% is reasonable and appropriate for purposes of this proceeding.

71. Based on the other findings and conclusions set forth in this Order, the appropriate level of income tax expense under present rates for use in this proceeding is $8,607,000.

72. The level of other interest expense appropriate for use in this proceeding is $208,000.

73. The level of interest on tax deficiencies appropriate for use in this proceeding is $171,000.

74. The reasonable level of test year operating revenue deductions for NC Power (excluding fuel expense) after normalization and pro forma adjustments, under present rates is $115,757,000.

75. The proper capitalization ratios for use in this proceeding are as follows:

Long-Term Debt	45.227%
Preferred Stock	9.955%
Common Equity	44.818%
Total	100.000%

76. The proper embedded cost rates of long-term debt and preferred stock for use in this proceeding are 8.024% and 5.598%, respectively.

77. Estimates of the cost of common equity capital derived by use of both the constant growth form of the discounted cash flow (DCF) model and the FERC risk premium model should be accorded the greatest weight in determining the appropriate cost of equity in this proceeding.

78. The non-constant growth DCF model and the risk premium methods employed by witness Avera should be accorded only minimal weight in this proceeding.

79. The Company does not plan a public offering of its common stock in the near future.

80. In a foregoing finding of fact, an adjustment has been made to the cost of service for actual jurisdictional test-year expenses associated with the Company's stock purchase plans. No further adjustment to cost of service, rate base, or cost of capital to compensate for flotation costs is appropriate.

81. The appropriate cost of common equity for use in this proceeding is 11.80%.

82. Combining the capitalization ratios and the cost rates for each component of capital adopted for use herein, the Commission finds that the rate of return which the Company should be allowed an opportunity to earn on its rate base is 9.48%.

83. NC Power should be authorized to increase its annual level of gross revenues under present rates by

$10,642,000 (excluding fuel revenue). After giving effect to the approved increase, the annual revenue requirement for NC Power (excluding fuel revenue) is $155,019,000, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

84. The revenue increase adopted herein should be distributed to the various customer classes as follows:

	Rate of Increase Index
Residential	1.125
Small General Service	1.0
Large General Service	0.875
Outdoor Lighting	1.0
Traffic Signals	1.0
Overall	1.0

85. The summer/winter differential of 1.0¢/kWh is appropriate for setting residential non-time of use rates in this case.

86. The basic customer charge for residential non-time of use rates should be set to a level of $9.50 per month in designing rates to produce the level of revenue found appropriate for the residential rate class in this case.

87. NC Power proposed a new Line Extension Plan as part of its original filing in this proceeding. The plan was subsequently modified during the hearing by means of a stipulation between the Company and the Public Staff regarding revised language that would permit a residential customer to request overhead construction rather than underground construction in the application of the revenue test.

88. The proposed new Line Extension Plan will recover approximately $1 million per year more from new residential customers and approximately $75,000 per year more from new non-residential customers.

89. More complete recovery of investment in new distribution plant will help delay future general rate increases, and it will avoid much of the investment for new customers that has been charged to existing customers.

90. Overhead line extensions should continue to be available to customers requesting overhead service, and associated construction costs should be determined on a case-specific basis.

91. The proposed new Line Extension Plan, as modified during the hearing, is appropriate and should be approved to become effective 90 days after the date of this Order.

92. The Company offers a reduction to residential energy and demand charges for customers whose dwellings meet certain thermal integrity requirements.

93. Historically, the thermal requirements to qualify for the reduction have been substantially more stringent than those required by the North Carolina Building Code for all residential construction.

94. The North Carolina Building Code Council has adopted new residential building standards to be effective April 15, 1993, which are substantially more stringent than those currently in place.

95. NC Power has agreed to file new revised standards to qualify for the residential conservation reduction (RCR) prior to April 15, 1993.

96. It is appropriate to modify Schedule 6C, Schedule SG, and Schedule CS to allow for two curtailment requests per day during the winter season as proposed by the Company.

97. The rate designs and rate schedules proposed by the Company are reasonable and appropriate except as specifically modified herein.

98. The change proposed by the Company to paragraph II.A.1 of the Company's Terms and Conditions for the delivery of electric service rules and regulations has been withdrawn at this time and should not be approved.

99. The Terms and Conditions proposed by the Company are reasonable and appropriate except as specifically modified herein.

100. The test period for the fuel clause proceeding (Docket No. E-22, Sub 335) is the 12-months ending June 30, 1992.

101. The fuel proceeding test period per book system sales are 57,794,906 mWh.

102. The fuel proceeding test period per book system generation is 61,448,089 mWh which includes various energy generations as follows:

	mWh
Coal	25,992,366
Internal Combustion	1,413,808
Heavy Oil	1,912,993
Natural Gas	87,836
Nuclear	22,978,300
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,268,968
Other	5,234,861
Interruptible Sales	(2,551,212)

103. The normalized system nuclear capacity factor which is appropriate for use in this proceeding is 69.24%.

104. The normalized generation is based on the 12-month test period ending June 30, 1992.

105. The adjusted test period sales of 58,613,478 mWh results from an additional 280,695 mWh of customer growth, 183,088 mWh of additional customer

usage, and an additional 354,789 mWh associated with weather normalization added to fuel test period system sales of 57,794,906 mWh.

106. The adjusted test period system generation for use in this proceeding is 62,309,169 mWh which includes various energy generations as follows:

	mWh
Coal	28,130,404
Internal Combustion	1,530,090
Heavy Oil	2,070,346
Natural Gas	95,061
Nuclear	20,474,196
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,784,633
Other	5,665,469
Interruptible Sales	(2,551,212)

107. The appropriate fuel prices for use in this proceeding are as follows:

A. The coal fuel price is $14.26/mWh.

B. The nuclear fuel price is $4.59/mWh.

C. The heavy oil fuel price is $24.90/mWh.

D. The natural gas price is $30.59/mWh.

E. The internal combustion turbine (IC) fuel price is $21.33/mWh.

F. The fuel price for other purchased and interchanged power is $15.12/mWh.

G. The total fuel cost for interruptible sales is $28,446,000.

H. Hydro, pumped storage, and non-utility generation (NUG) have a zero fuel price.

108. The adjusted system fuel expense for the July 1, 1991, to June 30, 1992, test period for use in this proceeding is $639,430,000.

109. The appropriate base fuel factor for this proceeding is 1.091¢/kWh, excluding gross receipts tax.

110. The Company's North Carolina test period jurisdictional fuel expense overcollection is $1,308,510. The adjusted North Carolina jurisdictional test year sales are 2,629,412 mWh.

111. Interest expense associated with the overcollection of test period fuel revenues amounts to $218,085, based upon a 10% annual interest rate.

112. The Company's Experience Modification Factor (EMF) and interest combine for a decrement of 0.058¢/kWh, excluding gross receipts tax.

113. The final fuel factor is 1.033¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact is contained in the Company's application and in the Commission's record. These findings are generally informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Company witnesses Rhodes and Hughes and the public witnesses who appeared in Ahoskie, Elizabeth City, Williamston, and Roanoke Rapids. The only witness to complain about service was public witness William Pruden, who addressed service reliability on the Outer Banks. Witness Pruden was particularly concerned about multiple interruptions, or "blips", in the service. Witness Hughes acknowledged that the Outer Banks present a special problem for the Company and described the steps NC Power is taking to overcome these problems, including spraying of the lines to remove storm driven salt

spray. Based on the single complaint of witness Pruden as compared to the multiple witnesses praising the Company, and on the steps the Company is taking to address the Outer Banks situation, the Commission concludes that NC Power is providing good service to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence as to the reasonableness of the allocation of the Vepco system cost to the North Carolina retail jurisdiction is found in the testimony and exhibits of Company witness Evans, Public Staff witness Turner and CIGFUR witness Phillips.

Both Company witness Evans and Public Staff witness Turner recommended the use of the Summer/Winter Peak and Average (SWPA) method for determining jurisdictional allocation and the revenue requirement for the North Carolina retail jurisdiction. CIGFUR witness Phillips did not agree.

As discussed elsewhere herein, the Commission concludes that the SWPA method is the most appropriate cost allocation method for determining jurisdictional allocation and the revenue requirement for the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence as to the most reasonable method for determining North Carolina retail customer class cost responsibility is found in the testimony of Company witness Evans, Public Staff witness Turner, and CIGFUR witness Phillips.

While the Company's witness recommended the use of the Summer/Winter Peak and Average (SWPA) method for determining jurisdictional cost responsibility and revenue requirement, he recommended that the Average and

Excess method (A&E) be used to determine customer class cost responsibility. The Public Staff witness recommended that the SWPA method be used to determine both jurisdictional cost responsibility and customer class cost responsibility. The witness for CIGFUR agreed with the Company that the SWPA method was not appropriate for determining customer class cost responsibility.

Witness Evans explained that the factors to be considered in allocating the generating or production cost of the system among its customers should be consistent with the production cost each customer class load imposed on the utility. This system cost is a function of peak loads, which require a utility to build or purchase capacity, and of energy consumption, which dictates the type of plant to be built or the type of power to be purchased. Base load plants require high capital costs but have lower fuel costs and are expected to operate many hours a year. Peaking plants have low capital costs but have high fuel costs and operate for only a few hours a year. Intermediate plants have moderate capital costs and fuel costs and operate many more hours than peaking units but fewer hours than base load units. The type of plant the Company builds is based on total costs, including both fixed and variable costs. The decision to build base load capacity is expected to reduce operating costs through the use of lower heat rates and lower cost fuel; therefore, the cost of base load capacity should be viewed as having been incurred, at least in part, to provide lower cost energy. Witness Evans stated that he believed the demand allocation factor should be energy weighted in some fashion in order to recognize that the annual kWhs consumed have capacity costs associated with them.

Witness Evans testified that all customers benefit from the diversity in usage patterns that arises from serving a variety of customer classes because such diversity results in a reduction in total capacity requirements for the system. He pointed out that the total system peak load is always less than the sum of the individual customer class

peak loads, reflecting the diversity of usage patterns. He proposed that such customer class diversity should be recognized in the cost allocation process by utilizing the maximum peak load for each class as an allocation factor rather than the load for each class at the time of the system peak. The use of the class peak loads rather than the coincident peak loads for each class is what distinguishes the A&E method from the SWPA method.

Witness Evans testified that a weakness of the SWPA method was its use of both summer and winter peaks, and he insisted that the Company's summer peak alone is the driving criteria behind the Company's capacity expansion plan. He contended that the SWPA method would allow a customer class to increase its contribution to one seasonal system peak while decreasing its contribution to the other seasonal system peak as a means of reducing its overall demand related allocation factor.

Public Staff witness Turner recommended that the Commission continue to approve the SWPA cost allocation method for use in determining both jurisdictional and customer class cost responsibility in this case. He stated that this method has been approved by the Commission in the Company's previous two proceedings since 1983: Docket Nos. E-22, Sub 273 and 314. The method has also been approved for use in all CP&L general rate cases since 1982: Docket Nos. E-2, Sub 444, Sub 461, Sub 526, and Sub 537.

Witness Turner explained that the SWPA method uses an allocation factor based on two components weighted by system load factor. The first component is based on the average of summer and winter peaks at the time of the system's peak demand. The second component is based on average demand for the year. System load factor is used as a proxy for determining the portion of plant allocated by average demand. Although the amount of production capital required to produce energy is not precisely known, use of load factor as a proxy works well

in this regard because it will allocate more plant by average demand as the load factor increases and less plant as the load factor decreases. Similarly, as the Company's system load factor increases system planning will tend to meet additional load requirements with base load capacity. Conversely, as system load factor declines system planning will tend toward peaking units to meet additional load requirements.

Witness Turner stated that an analysis of investment in generating plant required to meet the system minimum load shows that approximately 60% of the Company's total production plant investment is required to meet the system's minimum load. The minimum load of 4,132 MW maintained continuously equates to an energy requirement of 36,196,320 mWh. To meet this demand or to produce this minimum energy requirement, the Company dispatches its most efficient units, which also are the units with the greatest investment per MW. The investment in these units represents approximately 60% of the Company's total investment in production plant.

Witness Turner explained that the SWPA allocation method recognizes that generating units are built to run for varying periods of time and that the increased cost to build base load units is related to average demand or energy. Peaking units, costing in the order of $400 to $500 per kW, are built to run only during the times of peak demands. These units have the lowest capital cost and highest fuel cost and are not considered economical to run except for a few hours a year. Base load units, costing in the range of $1,000 to $2,000 per kW, require the largest capital investment but have the advantage of low fuel cost (0.5 to 1.5¢/per kWh.) They are proven economical because of the required long running time. The difference in capital cost is, therefore, related to the long run time or total energy produced. Because a portion of the base load unit fixed cost investment is related

to providing long running capability at low fuel cost, it is reasonable to allocate a portion of the fixed cost investment by using average demand.

CIGFUR witness Phillips testified that the SWPA method is no longer appropriate for cost allocation between customer classes. He contended that the SWPA method does not accurately reflect the cost causation of each class and is in direct conflict with demand side management programs. He stated his preference for the summer coincident peak allocation method, but indicated that if the Commission determines that energy usage should be a part of the cost allocation formula, the A&E method is more appropriate than the SWPA method.

CUCA supported the position of NC Power and CIGFUR on cost allocation, and the Attorney General supported the position of the Public Staff. CUCA insisted that all fixed costs of production plant should be classified as demand related and that any allocation of fixed costs by energy usage unlawfully discriminates against industrial customers. The Attorney General contended that CIGFUR's and CUCA's support for the A&E method reflects the fact that it produces results similar to the coincident peak method they usually support even though the A&E method includes an allocation of some fixed costs based on energy usage.

The Commission is of the opinion that the SWPA method should be retained in this proceeding for cost allocations between jurisdictions and between customer classes. The Commission is not persuaded that the diversity in class usage patterns provides sufficient justification for utilizing class maximum peaks in the allocation formula rather than class coincident peaks. The class coincident peaks are also a measure of diversity between classes, and they are related to the needs of the entire system as a whole. This becomes significant in view of the fact that generating units are designed to meet the

needs of the entire system as a whole, not the needs of any individual class of customer. Since the only real difference between the A&E method and the SWPA method is the use of class maximum peaks by the A&E method and the use of class coincident peaks by the SWPA method, the SWPA method better reflects the diversity between class usage patterns as related to the system as a whole.

The Commission is also not persuaded in this proceeding that the allocation formula should exclude consideration of energy usage as suggested by CIGFUR and CUCA. The reasons remain the same as explained in previous general rate orders for both NC Power and for Carolina Power & Light Company. In brief, large base load generating units, which constitute the lion's share of the fixed cost investment in generating plant, are designed to achieve lower operating costs over their entire period of operation. While operation of such base load units is essential during peak periods, the large fixed cost investment in such units can only be justified by the savings in operating costs for such units during nonpeak periods.

The Commission is also not persuaded that use of both the summer coincident peak and the winter coincident peak for the demand related allocation factor is a weakness in the SWPA method. Use of only a summer coincident peak or only a winter coincident peak could give some customer classes a free ride, due to the fact that some classes may contribute greatly to one of the peaks and hardly anything to the other.

Company witness Evans testified that determination of an allocation method for fixed costs of production should also consider how fuel costs are recovered. He indicated that an allocation method should match the recovery of fixed costs with the average recovery of fuel costs. He recommended in his rebuttal testimony that if the Commission adopted the SWPA method for cost allo-

cation between customer classes in this proceeding, an additional $1.3 million should be allocated to all classes except the Large General Service (LGS) class in order to compensate the LGS class for the fact that most of the LGS class kWh usage comes from low fuel cost generation. However, he agreed on cross-examination that if a greater share of low cost nuclear fuel is allocated to the LGS class, then a greater share of nuclear decommissioning cost should be allocated to them as well.

CIGFUR witness Phillips testified that if the adopted cost allocation method is premised on the theory that some customer classes utilize more of the base load generating plants than others, then the lower energy costs resulting from those base load plants should also be allocated to those classes. He stated that there should be symmetry between allocation of fixed costs and energy related costs in any method. He contended that if the Commission allocates a greater share of the fixed costs of base load units to the LGS class, then the LGS class should be allocated a greater share of the low fuel costs from those base load units.

In response to the Company's and CIGFUR's concern about fuel allocation under the SWPA method, witness Turner stated that the Public Staff would be receptive to proposals to charge different energy costs to different customer classes. He explained that the information needed to do such an allocation would have to be provided by the Company and would have to include such data as the load shape for the various customer classes and the amount of fuel cost associated with each plant supplying power to those customer classes. In response to questions on re-direct, witness Turner stated that information needed to make recommendations on cost of service comes from the Company. In this case the Company filed Commission-ordered cost studies, but it did not file a fuel allocation study, and it has not been ordered to do so by the Commission.

The Commission concludes that the Company should make a study of the fuel costs and other energy costs incurred to serve the LGS customer class relative to the remainder of the system. The study should also attempt to determine the fixed costs of generating units required to serve the LGS customer class relative to the remainder of the system to the extent it is feasible to do so. The studies may be based upon the fixed costs and variable costs of the generating units actually dispatched to serve the LGS class load, or they may be based upon a production simulation model or other method agreed upon between the Company and the Public Staff. The Commission is further of the opinion that the Company and the Public Staff should attempt to agree on mutually acceptable criteria for making the studies, and that they should seek appropriate input and comment on making the study from CIGFUR, CUCA and any other party to this proceeding who desires to participate. The results of the studies and supporting workpapers should be filed with the Commission and the Public Staff within 12 months after the date of this Order. The Company should also file quarterly reports with the Commission regarding the progress of the studies and agreements as to study criteria and methodology, with the first report due approximately three months after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The amount of materials and supplies proposed by both the Public Staff and the Company is $13,090,000.

Based on the foregoing, the Commission concludes that the appropriate level of materials and supplies for use in this proceeding is $13,090,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The amount of cash working capital investment proposed by both the Public Staff and the Company is $(2,458,000).

Based on the foregoing, the Commission concludes that the appropriate level of cash working capital investment for use in this proceeding is $(2,458,000).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Schools and Public Staff witnesses Dietz and Maness. The rate base proposed by both the Public Staff and the Company is $367,831,000.

Based on the foregoing, the Commission concludes that the Company's reasonable rate base used and useful in providing service to its North Carolina retail customers for purposes of this proceeding is $367,831,000, made up of the following components:

Item	Amount (000's)
Electric plant in service including nuclear fuel	$598,046
Accumulated depreciation	(166,889)
Accumulated amortization of nuclear fuel	(36,842)
Net electric plant in service	394,315
Materials and supplies	13,090
Cash working capital	(2,458)
Accumulated deferred income taxes	(37,101)
Other cost-free capital	(15)
Total rate base	$367,831

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-17

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and was not opposed by any party.

The testimony and exhibits of witness Evans show the level of sales and revenues for the test period ending December 31, 1991, through the update period ending September 30, 1992, as follows:

Sales	mWh
North Carolina jurisdictional sales	2,521,134
Unbilled sales	8,795

Basic Revenues	Amount
Basic rate schedules	$134,938,156
Unbilled revenues	430,599
Load management credits	(176,117)
Facilities charges	408,313
Miscellaneous service charges	856,470
Total	$136,457,421

There is no other evidence in the record contesting the level of sales and revenues discussed above. The Commission concludes that these levels are reasonable for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-21

The evidence for these findings of fact is based on the testimony and exhibits of Company witness Evans and Public Staff witness Turner.

Witness Evans filed testimony and exhibits adjusting per book sales and revenues related to whether normalization, customer growth, and increased usage for the test period ending December 31, 1991, through the update period ending September 30, 1992. Witness Evans' ad-

justment is $6,746,512 based on an adjustment of 132,606 mWh of additional sales. The Public Staff accepted these numbers.

The Commission concludes that the adjustment for weather normalization, customer growth, and increased usage is reasonable and appropriate for use in determining the end-of-period level of kWh sales and revenues. The appropriate adjustment to revenues for the period ending December 31, 1991, through the update period ending September 30, 1992, due to weather normalization, customer growth, and increased usage is $6,746,512 based on additional sales of 132,606 mWh.

Based on the foregoing conclusions, for the test period ending December 31, 1991, through the update period ending September 30, 1992, the reasonable and appropriate adjusted level of sales is as follows:

	mWh
North Carolina Jurisdictional Sales	2,521,134
Unbilled sales	8,795
Weather normalization	(5,308)
Customer growth	(6,447)
Increased usage	144,361
Total	2,662,535

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-24

With the exception of the allocation of DSM cost, the evidence in the record supporting these findings of facts is contained in the testimony and exhibits of Company witness Evans and was not contested by any party. The evidence in the record as to the appropriate assignment of DSM cost is found in the testimony of witness Evans and CIGFUR witness Phillips.

Company witness Evans filed supplemental testimony proposing an adjustment to North Carolina jurisdictional

expenses based on the DSM Cost Recovery Joint Stipulation between NC Power and the Public Staff in Docket No. E-100, Sub 64. The adjustment allocates certain DSM revenue credits to the North Carolina jurisdiction whereas the Company's original filing directly assigns the credits. The adjustment of $(514,000) is the difference in the expenses allocated and directly assigned.

CIGFUR witness Phillips testified that because cost could be directly assigned, it is unnecessary to allocate DSM costs. Witness Phillips argued that allocation of cost should be used when booked data necessary to determine cost responsibility does not exist.

Based on the evidence in the record, the Commission concludes that allocation of DSM credits as proposed by the Company is reasonable and appropriate. The Commission concludes that allocation of system-wide DSM costs is appropriate because all customer classes and jurisdictions benefit from DSM programs. While all classes may not participate in a particular DSM program, all classes do benefit from the overall benefits of DSM. It is therefore equitable for all classes to bear a portion of the cost of DSM programs. Thus, the DSM related adjustment of $(514,000) is reasonable.

Based on the foregoing conclusions and the Commission's previous conclusions, the Commission now concludes that the reasonable and appropriate level of end-of-period revenues, excluding other miscellaneous revenue, for the test period ending December 31, 1991, through the update period ending September 30 , 1992, is $142,683,807 as shown below:

	Amount
Basic rate schedule revenues	$134,938,156
Unbilled revenues	430,599
Weather normalization, customer growth and increased usage revenues (including growth in load management)	6,746,512
Subtotal	142,115,267

Load management credit	(176,117)
Load management growth	(6,126)
DSM cost allocation adjustment	(514,000)
Facilities charges	408,313
Miscellaneous service charges	856,470
Total	$142,683,807

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the exhibits and other data and records filed by the Company in this proceeding. In addition to the end-of-period revenue of $142,683,807, found reasonable and appropriate in the Evidence and Conclusions for Findings of Fact Nos. 22-24, the Company recorded during the test year $1,824,000 in other miscellaneous revenue. Additionally, the Company made an adjustment of $(159,000) to annualize pole attachment revenue and adjustments totalling $28,000 to annualize Old Dominion Electric Cooperative reserve revenue. No party contested the inclusion of either the per books other miscellaneous revenue or the adjustments made by the Company.

The Commission therefore concludes that the proper gross revenue for the test year (excluding fuel revenue) under present rates and after accounting and pro-forma adjustments is $144,377,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-33

The evidence for these findings of fact is found in the testimony of NC Power witnesses Rhodes and Ross and Public Staff witness Powell. The prefiled revised testimony of Company witness Ross indicated that during the period December 28, 1990, through November 30, 1992, 16 additional NUGs declared commercial operation with a combined summer capability of 1,760 MW. These

NUG projects and their commercial operation dates were listed on his Exhibit GBR-1, Schedule 6, revised. These are as follows:

NUG Additions	Date On-line
Battersea Dam	12/31/90
Richmond Power Enterprises	03/13/91
Dale	03/29/91
Wythe Park Power #3	07/29/91
I-95 Landfill	01/01/92
Hadson #12—Altavista	02/22/92
Hadson #11—Southampton	03/07/92
Cogentrix of Richmond #1	05/01/92
Doswell #2	05/03/92
North Branch Project	05/05/92
Doswell #1	05/10/92
Commonwealth Atlantic LP	06/05/92
Harvell	06/30/92
Hadson #13—Hopewell	07/01/92
Cogentrix of Richmond #2	08/01/92
Mecklenburg	11/06/92

NC Power witness Rhodes testified that in 1986 Vepco decided to deal with NUG offers by conducting a solicitation because it believed it was receiving NUG capacity offers in amounts greater than its projected needs for the foreseeable future. The Company instituted its solicitation process by sending out a letter on December 23, 1986, to all developers with whom the Company had contact or who had shown an interest in executing a purchased power agreement with the Company.

Witness Rhodes further testified, in response to questions from the Public Staff on cross-examination, that the Company sought 700 MW of capacity through its December 1986 solicitation and received bids of 5,083 MW in response. The Company selected ten projects for negotiation and ultimately signed contracts in June 1987 for seven projects totaling 1,264 MW. Six of these projects are in operation with a summer capacity rating of 1,305

MW and an average capacity rating of 1,412 MW. Vepco's status report filed on August 30, 1992, in Docket No. E-100, Sub 41, indicates that the one remaining project from the 1986 solicitation was placed in default on July 23, 1991.

In March 1988, Vepco issued a formal Request for Proposals seeking 1,750 MW of capacity. It received bids for 95 projects totalling 14,653 MW. It ultimately signed contracts for 19 projects totalling 2,086 MW. Eleven projects are still active totalling 1,291 MW, seven of which currently are operational with a dependable capacity of 982.4 MW.

Witness Rhodes further testified that the Company undertook a solicitation for peaking power in October 1988, from which no contracts were signed. An all-source solicitation for 1,100 MW was undertaken in 1989, which resulted in 11,000 MW being offered. Contracts were signed for 442 MW and Vepco announced it would build its own 400 MW coal plant. No projects from this solicitation are currently in operation.

In response to cross-examination questions from the Public Staff, NC Power witness Rhodes conceded that the Virginia SCC had expressed significant concerns about the Company's capacity planning process, including whether its decisions to buy or build have been based on questionable cost data, its failure to compare its estimated construction costs with each individual NUG project in its winning package, and its bias toward NUG capacity purchases.

In response to cross-examination by the Public Staff, witness Rhodes also stated that the Company did not use a Company-built option for a direct comparison on a unit-by-unit basis in the spring of 1988 solicitation. He explained that what the Company did was make sure that the package of NUG projects for which Vepco signed contracts was cheaper than the amount it would have cost

the Company to have built that capacity itself. He agreed on cross-examination that there was a significant risk that the low-priced winning bidders could fall out leaving the Company only with the relatively high-priced ones.

With regard to the concerns of the Public Staff, witness Powell testified that the contracts the Company has entered into for NUG projects contain a variety of terms regarding how total costs are divided between capacity and energy costs and how capacity costs are structured. Of particular concern to witness Powell were the ratchet arrangements where higher capacity payments are paid in earlier years and lower payments are paid in the final years of the contracts.

Witness Powell also testified that the Public Staff had not evaluated the reasonableness and appropriateness of individual NUG contracts resulting from the Company's various solicitations. He indicated that the Public Staff had focused on the reasonableness of the NUG expenses at issue in this proceeding.

On May 7, 1987, the Commission entered an Order in Docket No. E-100, Sub 53, established standard rates and contract terms for qualifying facilities pursuant to Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and G.S. 62-156(b). In that Order, the Commission stated that:

> Negotiated contracts between a utility and a qualifying facility should, upon execution, be submitted to the Commission. The Commission will conduct a general review of such contracts to determine whether they comply with the provisions of this Order. If it appears that they do, such contracts will be approved for filing with the Commission. The Commission may, on its own motion, conduct further, more detailed review of the contracts at that time by way of such hearings or other proceedings as it may order. Further, such contracts, after being

approved for filing, shall be subject to review in the context of the utility's next filed general rate case or by a complaint proceeding, just as would any other contract by the utility. By this procedure, the Commission seeks to ensure that a meaningful and public review is conducted with respect to such contracts.

The Public Staff, through witness Powell, states that it has not evaluated the appropriateness of any of the individual NUG contracts at issue in this proceeding; i.e., those projects currently in commercial operation. The Public Staff has raised a number of concerns regarding the reasonableness of the various NUG contract terms related to capacity payments. According to our Order in Docket No. E-100, Sub 53, the contracts in question should have been investigated in this rate case. The Public Staff was, however, apparently unable to evaluate NC Power's NUG contracts during the course of its investigation. That being the case, the Commission hereby requests the Public Staff to investigate the contracts in question and any other NUG contracts for projects which begin commercial operation after the date of this Order and present the results of such investigation during NC Power's next general rate case in order to ensure that a meaningful and public review has been conducted. Until such time as the NUG contracts in question have been investigated by the Public Staff, the Commission finds good cause to include in rates, as recommended by the Public Staff, a reasonable and representative level of NUG capacity costs for purposes of this proceeding only.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-59

The evidence for these findings of fact is found in the testimony of Company witnesses Ross and Edwards, the testimony of Public Staff witness Powell, and exhibits associated with their testimony.

Company witness Ross testified that during the period December 28, 1990, through November 30, 1992, 16 additional NUGs declared commercial operation. Public Staff witness Powell testified that he examined the reasonableness of the NUG capacity payments that NC Power has requested in this proceeding. He recommended an adjustment with respect to three NUG projects, which will be referred to hereinafter as the Ultra Cogen projects or the Hadson projects.[1] Vepco entered into the three contracts at issue with Ultra Cogen Systems, Inc., (Ultra Cogen) as a result of arbitration proceedings before the Virginia State Corporation Commission (SCC). Vepco currently is obligated to pay $64 million on a system basis for annual capacity costs for the three Hadson projects and is seeking to recover the North Carolina retail jurisdictional allocation of these costs, approximately $2.8 million. The Public Staff recommends that $1.39 million of these capacity costs be disallowed for ratemaking purposes in North Carolina. A history of these projects is necessary to understand the issues presented.

Vepco's December 1986 solicitation letter was sent to Ultra Cogen, at its request, on January 13, 1987. Ultra Cogen proposed nine projects. Ultra Cogen's proposals were rejected in March 1987 because the proposed price was excessive and Ultra Cogen was unwilling to accept certain terms and conditions. Vepco offered to purchase energy only from Ultra Cogen, and it suggested that Ultra Cogen participate in the Company's next solicitation if Ultra Cogen wished to sell capacity. Vepco selected other proposals from the 1986 solicitation. Six of

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[1] The projects were developed by Ultra Cogen Systems, Inc. Ultra Cogen subsequently was purchased by Hadson Power, and these projects became known as Hadson Power 11—Southampton, Hadson 12—Altavista, and Hadson Power 13—Hopewell. Hadson was recently purchased by LG&E Development Corporation. These projects are now owned by a conglomerate of limited and general partners, including subsidiaries of Westmoreland Coal and a Chrysler Capital Corporation subsidiary.

these projects have come on line, and they average $141/kW for capacity payments.

In October 1987 the Virginia SCC initiated a generic review of certain policy issues with respect to competitive bidding schemes such as Vepco's solicitation. The SCC issued a policy statement on competitive bidding in Case No. PUE870080 on January 29, 1988. In this order, the SCC concluded that federal law does not require a utility to pay full administratively determined avoided costs and that avoided costs may be determined through competitive bidding. It stated that "we believe a system of competitive negotiation such as we have described would be a very efficient and fair means of approximating real, not theoretical, avoided costs." The SCC's policy statement went on to provide that in evaluating specific proposals, favorable weight should be assigned to the use of Virginia fuels, manpower, and other State resources; the benefits to be derived by the industries and communities associated with particular projects; and other identifiable economic and societal benefits to the people of Virginia.[2] With this policy statement in hand, Vepco put together its 1988 solicitation.

While the SCC's generic review was underway, Ultra Cogen initiated arbitration proceedings for its nine projects (two of which were in West Virginia) by filing arbitration petitions with the SCC between November 12, 1987, and December 3, 1987. Ultra Cogen asked the SCC to order Vepco to enter into power purchase agreements including payments for capacity. Ultra Cogen's first petition for arbitration involved a proposed cogeneration facility at The Lane Company, Inc. (Lane) in Altavista, Virginia (Case No. PUE870088). The petition indicated that the facility would burn coal expected to be from or transloaded in Virginia, that there were signifi-

[2] It is worth noting that this Commission lists various factors which we expect utilities to consider in negotiating with QFs, but we do not list factors such as these.

cant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the community and the Commonwealth would result.

Vepco requested dismissal of the petitions on the ground that the SCC had expressed its general approval of competitive bidding in its January 29, 1988, Order in Case No. PUE870080. The SCC refused to dismiss and decided that it would arbitrate Ultra Cogen's petitions by Order dated February 26, 1988, one month after the SCC's policy statement on competitive bidding. The SCC stated it would approach the arbitrations in an innovative fashion, designed to deal with the subject in a prompt but effective manner. The SCC designated Commissioner Harwood to serve as arbitrator and provided that the arbitrator's conclusions would be final and that Vepco would be bound by them. The SCC ruled that the arbitration would develop appropriate contracts *for capacity purchases* by Vepco from Ultra Cogen and that the amount of the capacity to be sought by future solicitations would be limited by the amount of capacity resulting from the arbitration.

Vepco issued its 1988 solicitation letter on March 1, 1988. Vepco's position in the arbitration proceedings was that the prices resulting from the 1988 solicitation (or, alternatively, the 1986 solicitation) should be used to set prices for the Ultra Cogen contracts. (This is the position now taken by the Public Staff and opposed by the Company.) The Virginia arbitrator disagreed. By a memo issued on April 27, 1988, he required the contracts to be based on avoided costs of Vepco's Chesterfield 7 as those costs were projected on November 12, 1987, the date the first petition for arbitration was filed. This memo was issued by the arbitrator two months into Vepco's 1988 solicitation.

The arbitrator followed up just one month later with an Interim Order of May 27, 1988, in which he established capacity and energy prices, along with other key terms and conditions, for the Ultra Cogen projects. He established the capacity price at $341/kW for the first 15 years of operation. Ultra Cogen's energy prices were established based on the assumption that coal prices would increase in the future. In fact, Vepco's fuel reports on file with this Commission show that from 1984 through 1987 the cost of coal was decreasing and that it has remained relatively stable ever since. The arbitrator noted that Ultra Cogen and Vepco had agree that the number of projects would be reduced to four projects within Vepco's service territory.

Draft contracts were subsequently submitted, and the arbitrator entered his Final Order requiring Vepco to sign the contracts. In this Order, the Hearing Examiner expressly recognized that "the Agreements reflect negotiations and rulings based on the unique circumstances of these proceedings (including that they are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." Vepco signed the contracts on October 7 and 8, 1988. It did not appeal the SCC arbitration orders to the courts. Three of the four projects came into commercial operation in 1992. (The fourth project encountered permitting problems and has been placed in default).

At about the same time, Vepco signed contracts resulting from its 1988 solicitation during December 1988 and January 1989. Seven of these projects came into commercial operation in 1990 and 1992. They average $171/kW in capacity payments.

Public Staff witness Powell compared the operation of the Hadson projects, which operate at a capacity factor of 27.1%, to the projects resulting from the 1988 solicitation, which operate at a capacity factor of 35.9% The capacity costs of the Hadson projects are twice the average

costs of the 1988 projects. Witness Powell recommended that the allowable capacity costs for the Hadson projects should be the average capacity costs of the 1988 package. Consequently, he recommended that $170/kW, or $1.39 million, be disallowed. On cross-examination, he testified that he was evaluating what the North Carolina ratepayers should pay and that the costs the Company seeks to recover are too high.

Company rebuttal witness Edwards testified that this Commission should accept the Hadson capacity payments as reasonable because they resulted from arbitration before the Virginia SCC and because there is no evidence of imprudence on the Company's part. He further testified that using the costs from the projects selected from the 1988 solicitation was totally inappropriate. He conceded, however, that the Company had argued before the Virginia arbitrator that the results of the 1988 solicitation (or, alternatively the 1986 solicitation) should be used to determine the avoided costs for the Hadson projects.

The Public Staff's recommended disallowance of $1.39 million of the Hadson capacity costs raises several issues. First, the Commission must determine whether the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C.A. § 824a-3, preempts State regulatory action or otherwise binds this Commission to follow the Virginia SCC's determination of avoided costs. We conclude that it does not.

Section 210 of PURPA requires electric utilities to purchase power from qualifying cogeneration and small power production facilities (QFs). The rates for such purchases must be just and reasonable to the utility's consumers and in the public interest and they must not discriminate against QFs. PURPA provides that the rates not exceed the incremental costs of alternative electric energy, referred to in the FERC regulations as "avoided costs." 16 U.S.C.A. § 824a-3(a) and (b); 18 C.F.R. § 292.304(a) and (b) (1980). The regulations define

avoided costs as the incremental costs to a utility of electric energy or capacity or both which, but for the purchase from the QF, the utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6) (1980). Energy costs are the variable costs associated with producing electricity, such as the costs of fuel. Capacity costs are the costs associated with providing the capability to deliver electricity, primarily the capital costs of facilities. The regulations set forth certain factors to be considered in determining avoided costs. 18 C.F.R. § 292.304(e) (1980).

QFs are exempt from the Federal Power Act (with a few exceptions that are not relevant here). 18 C.F.R. § 292.601(b) (1980). Implementation of the regulations dealing with regulated utilities' obligation to purchase from QFs and the rates for such purchases is left to state regulatory authorities. 18 C.F.R. § 292.401(a) (1980). Such implementation by the states may consist of issuing regulations, undertaking to resolve disputes between utilities and QFs, or any other action reasonably designed to implement the FERC regulations. In adopting its regulations, FERC noted that it

> supports the recommendation made in the Staff Discussion Paper that it should leave to the States . . . "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

Regulations Implementing § 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12214, 12226 (1980). FERC rules afford the states "great lati-

tude"; FERC recognized that "economic and regulatory circumstances vary from State to State and utility to utility." *Id.* at 12230-1. FERC expressly acknowledged that its regulations are not intended to divest a state regulatory agency of its authority under state law to review contracts for purchases as part of its regulation of electric utilities. *Id.* at 12233.

While PURPA and the FERC regulations do not allow rates greater than avoided costs, there may be a separate basis in state law or policy for such higher rates. Virginia SCC at one time adopted the policy of considering intangible environmental and societal benefits associated with QF power. The SCC approved a 15% rider to Vepco's avoided cost tariff for the purpose of giving reasonable weight to these benefits. PURPA does not provide for the addition of such a rider. The basis for this rider was Virginia law and policy. (This Commission has never added a rider of this sort to its determination of avoided costs in North Carolina.) The 15% rider is no longer required in Virginia, but, as discussed below, it is clear that the arbitrator considered economic benefits unique to the State of Virginia in setting the Hadsen capacity payments.

Based on the foregoing, the Commission concludes that PURPA does not preempt state action. In fact, it mandates state action and expressly leaves the states flexibility to experiment and accommodate special circumstances. Thus, "avoided costs" can be determined quite differently by different jurisdictions. Further, PURPA does not preempt this Commission's authority to review QF contracts in setting rates for the electric utilities operating in North Carolina. This Commission, in setting rates for NC Power in North Carolina, is not bound to interpret PURPA in the same manner as the Virginia SCC or to provide for the SCC's consideration of benefits unique to Virginia.

A second issue raised by the Public Staff's recommendation is whether PURPA allows avoided costs to be determined by a competitive bidding procedure. In its policy statement on competitive bidding in Case No. PUE870080, the Virginia SCC concluded that the general concept of bidding for new power supplies is a permissible response to PURPA and the FERC regulations. The SCC reasoned that if competitive negotiations are properly undertaken, the costs paid by the utility are indeed its avoided costs of not dealing with another, similarly situated QF. This Commission's review of PURPA and the FERC regulations leads us to the same conclusion. The results of a competitive bidding process may be used as the soliciting utility's avoided costs.

A third issue is whether this Commission must make a finding of management imprudence in order to disallow part of the capacity costs associated with the Hadson contracts as unreasonable. Vepco takes the position that because the Virginia arbitrator ordered Vepco to sign the contracts, the Company was not imprudent and, absent a finding of management imprudence, the costs cannot be disallowed. The Public Staff asserts that expenses can be disallowed as unreasonable for a variety of reasons and that management imprudence is only one method of demonstrating unreasonableness. The Public Staff cites *State ex rel. Utilities Commission* v. *Carolina Power & Light Company*, 320 N.C. 1, 358 S.E.2d 35 (1987) (*CP&L Remand*), in which the North Carolina Supreme Court explicitly rejected CP&L's argument that absent a finding of management imprudence, the Commission was required to use CP&L's actual fuel expenses when fixing rates.

G.S. 62-133(b)(3) requires that the Commission ascertain the utility's "reasonable operating expenses" when setting rates. The Commission agrees with the Public Staff that imprudence is only one method of demonstrating that a given expense is unreasonable. Therefore it is

not improper to disallow prudently incurred but otherwise unreasonable expenses for ratemaking purposes.

For example, the Commission routinely adjusts expenses for abnormal weather, for unrepresentative nuclear capacity factors, and for customer growth. These adjustments have been upheld by the North Carolina appellate courts on several occasions. The case most specifically on point is the North Carolina Supreme Court's opinion in the *CP&L Remand* case cited by the Public Staff. This case involved the remand of a number of CP&L's general rate cases and fuel clause proceedings in the early 1980s. The remanded cases were consolidated, and several parties appealed the Commission's final order. On appeal, CP&L contended that the Commission had made no finding of management imprudence and, to the extent the Commission made findings concerning those questions, the Commission's findings were to the effect that the actions of CP&L's management were prudent. CP&L argued that "given the absence of any finding of management imprudence, the Commission was required to use CP&L's actual fuel expenses when fixing rates for the three general rate cases involved in this appeal." 310 N.C. at 11. The Supreme Court's response to this argument was: "We do not agree." *Id.* The Court cited *State ex rel. Utilities Commission* v. *City of Durham*, 282 N.C. 308, 193 S.E.2d 95 (1972), which involved the adjustment of test period fuel expenses to reflect substantially abnormal weather conditions. Although abnormal weather conditions are a factor clearly unrelated to management prudence, the Supreme Court found no error in the Commission's adjustment of test period expenses and revenue to take those abnormalities into account. The Court in the *CP&L Remand* case concluded as follows:

> Therefore, although management prudence may be an important factor considered by the Commission in a general rate case, management prudence *vel non*

> does not control the Commission's decision as to whether to adjust test period data to reflect abnormalities having a probable impact on the utility's revenues and expenses during the test period, in order that it may set reasonable rates in compliance with N.C.G.S. § 62-133.

320 N.C. at 12. The Court in fact found that the Commission had a duty to normalize or adjust expenses as necessary. *Id.*

The Commission's rule prohibiting the inclusion of political and promotional advertising in reasonable operating expenses is another example. Rule R12-13(a) provides in part:

> In ascertaining reasonable operating expenses pursuant to G.S. 62-133, no electric or natural gas utility shall be permitted to recover from its ratepayers any direct or indirect expenditures made by such utility for political or promotional advertising as defined in Rule R12-12 or for other nonutility advertising.

Rule R12-12(d) specifically excludes several types of advertising from the definition of political and promotional advertising. With regard to these exclusions, R12-13(c) provides that expenditures for these excluded types of advertising generally will be deemed to be reasonable operating expenses, but the Commission is not precluded from determining on a case-by-case basis the extent to which such expenditures exceed a reasonable level. Thus, while it may be prudent for utility management to engage in political and promotional advertising, the Commission's rule provides that the expenses for such advertising are unreasonable *per se*. Furthermore, the rule provides for the disallowance of unreasonable expenditures for other types of advertising.

Another example of the Commission determining the level of reasonable expenses without regard to the pru-

dence of the utility's actions is our decision filed on October 12, 1992, in Docket No. W-354, Sub 111, the most recent general rate case of Carolina Water Service, Inc. (Carolina Water). In this case, the Public Staff recommended that a portion of the expenses related to Carolina Water's headquarters in Northbrook, Illinois, be disallowed. Carolina Water's rebuttal evidence was to the effect that those expenses were prudent and reasonable. The Commission concluded that the level of Northbrook expenses had increased at an unreasonable level and therefore these expenses should be adjusted to a reasonable level. No finding of imprudence was made.

Other examples can be found in the present Order. In this Order we discuss several operating expenses in terms of reasonableness without any specific discussion or finding as to prudence.

Based on the foregoing, the Commission concludes that "reasonable," as used in G.S. 62-133, does not equate to "prudently incurred" and that a prudently incurred expense can be shown to be unreasonable for numerous reasons. Accordingly, the Commission rejects the Company's argument and concludes that management imprudence need not be shown for the Hadson capacity payments, or some portion of them, to be disallowed as unreasonable.

The issue to be decided is whether the level of expense for the capacity associated with the Hadson projects is reasonable for ratemaking purposes in North Carolina. The Commission concludes that it is not.

First, we need only compare the Hadson capacity payments with other, contemporaneous measures of avoided costs. Total annual capacity payments for the three Hadson projects are over $64 million systemwide. They average $341/kW. In contrast, the seven operational projects that came out of the 1988 solicitation average $171/kW. The Virginia SCC itself said that such a solicitation is a

good means of "approximating real, not theoretical, avoided costs." Vepco's 1986 solicitation produced operational projects that average $141/kW in annual capacity payments. Interestingly, the 1986 solicitation used Vepco's proposed Chesterfield 7 as a benchmark, and Vepco witness Edwards testified that "if you would publish a benchmark you'll see that most bids if not all of them will come in right at the benchmark price, and that's what we saw in the December '86 solicitation." When Chesterfield 7 was used to establish the avoided costs for the Hadson projects, it produced far higher capacity payments than when it was used as a benchmark for the 1986 solicitation. The Virginia arbitrator himself stated in a February 1990 Order that payments for the Doswell project, one of the projects from the 1986 solicitation, were based on the avoided costs of Chesterfield 7 and were reasonable. The Doswell capacity payments for this rate case are $146/kW. The Hadson payments, also based on Chesterfield 7, are $341/kW. All of this evidence tends to show that the Hadson capacity payments are out of line. The Hadson payments are also out of line with the Company's avoided costs in North Carolina. Schedule 19 sets forth this Commission's determination of Vepco's avoided costs. Schedule 19 is not directly applicable to projects the size of the Hadson projects; such large QF's must negotiate rates with the utilities. However, as a practical matter, the avoided costs set by the Commission provide a cap on negotiated rates. Based on the version of Schedule 19 approved at the time the Hadson contracts were executed, the Hadson capacity would have cost Vepco $17 million a year, rather than $64 million.

Second, it is very clear from the record in this proceeding that the SCC's treatment of the Hadson projects was directly related to expected benefits to Virginia from these projects. The arbitrator's Award and Final Order dated September 30, 1988, specifically recognizes that the Hadson contracts "reflect negotiations and rulings based on

the unique circumstances of these proceedings (including that [the projects] are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth)." The arbitration petition for the project at The Lane Company indicated that the facility would burn coal expected to be from or transloaded in Virgina, that there were significant benefits to Lane and its ability to continue to operate and employ 1,200 people, that approximately $60 million would be invested in the Altavista area which was of critical importance to the future economic health of Lane and the City of Altavista, and that jobs and economic benefits to the communtiy and the Commonwealth would result. These benefits flow to Virginia, not to North Carolina. For this reason, it may be reasonable for Virginians to pay the extra costs associated with the Hadson projects. But it is unreasonable for North Carolinians to pay such extra costs, and our responsibility is to set fair and reasonable rates for North Carolina. We cannot accept the assumption implicit in the Company's position that our authority to set rates for North Carolina—and, by extension, the authority of the North Carolina Supreme Court—is circumscribed by the decision of an arbitrator in Virginia.

Finally, we cannot help but note that Vepco itself argued before the Virginia arbitrator that the results of the 1988 solicitation should be used to set the capacity costs for the Hadson projects. This is exactly what the Public Staff is arguing now and the Company is opposing.

Based on the foregoing, we conclude that the capacity costs included in the arbitrated contracts for the three Hadson projects are not reasonable for ratemaking purposes in North Carolina.

In making this decision, we recognize our obligation to encourage QFs, but that is not the issue here. The issue here is ascertaining reasonable operating expenses for purposes of setting just and reasonable rates in North Carolina. We cannot find these expenses to be reason-

able for our purposes when they are well over twice contemporaneous measures of avoided capacity costs and when they were clearly influenced by economic benefits unique to the State of Virginia. This Commission also recognizes the position of Vepco. It is "caught in the middle" between our decision and that of the Virginia SCC, but that is not unique to this issue. That is an inevitable consequence of doing utility business across state lines. For example, we use a different cost allocation methodology than the Virginia SCC for purposes of allocating production costs between states, and the different methodologies mean that Vepco may collect more revenues or may collect less revenues than if both states used the same methodology. The same thing can happen any time this Commission and the Virginia SCC decide the same ratemaking issue and reach different conclusions. Still, this Commission must exercise its own judgment. Neither we nor the SCC is bound by the decision of the other.

Finally, we must determine what is a reasonable level of capacity costs for the Hadson project. Public Staff witness Powell testified that the Hadson projects should be compared to the NUG projects selected by Vepco as a result of its 1988 solicitation. He testified that there are seven operational NUG projects that were selected in the 1988 solicitation, the capacity costs for which the Company seeks to include in rates in this proceeding. These projects have a combined capacity factor of 35.9% and their average capacity cost is $171/kW. By contrast the average capacity factor for the Hadson projects is expected to be 27.1%. Powell testified that it is appropriate to compare the costs of a NUG to the costs of other NUGs and that the 1988 projects are appropriate to use because of timeliness and similar operation to the Hadson projects. He testified that it is reasonable to expect that similar operation would yield similar capacity costs. Because the capacity costs of the Hadson projects

are twice the average costs of the 1988 projects, witness Powell recommended that the allowable capacity costs for the Hadson projects should be the average capacity costs of the 1988 package. Consequently, he recommended that $170/kW, or $1.39 million, be disallowed.

Witness Powell also reviewed the projects that are in operation from the 1986 solicitation. Because of the time difference as to when the contracts were executed and other constraints, he did not include them in his calculation of the Public Staff's recommended capacity adjustment for the Hadson projects. His Exhibit KLP-1, however, shows that the six projects resulting from the 1986 solicitation have a combined capacity factor of 32.2% and that their average capacity cost is $141/kW. If the 1986 projects were used to adjust the $341/kW capacity costs of the Hadson projects, a disallowance of $200/kW (or $1.63 million) would be appropriate.

The Commission has already concluded that PURPA allows avoided costs to be determined through competitive bidding. While the average capacity cost for the 1986 solicitation could be used to adjust the capacity costs for the Hadson projects, the average capacity cost for the operational projects resulting from the 1988 solicitation is more appropriate. The projects resulting from the 1988 solicitation that are still active but not yet operational are not included in the average because there is no guarantee that they will become operational and no way to tell what their exact capacity costs will be until they come on line. Accordingly, NC Power's operation and maintenance expenses should be reduced by $1,390,000 to reflect the unreasonable portion of the capacity costs for the Hadson projects.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 60-74

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witnesses Rhodes, Schools, Chamberlain, Edwards, and Carney and Public Staff witnesses Maness, Powell, and Hinton. The levels of operating revenue deductions (excluding fuel expense) proposed by the Company and the Public Staff representing their final positions are set forth in the following schedule:

(000's Omitted)

Item	Company	Public Staff	Difference
Operation and maintenance expense	$ 76,530	$ 75,011	$(1,519)
Depreciation and amortization	21,912	20,606	(1,306)
Other taxes	11,100	11,100	—
Income taxes	7,747	8,628	881
Charitable contributions	89	—	(89)
Other interest expense	208	208	—
Interest on tax deficiencies	171	171	—
Total operating revenue deductions	$117,757	$115,724	$(2,033)

As shown in the above schedule, the Company and the Public Staff agree on the amounts to be included in operating revenue deductions for other taxes, other interest expense, and interest on tax deficiencies. The Commission thus concludes that the levels of other taxes, other interest expense, and interest on tax deficiencies appropriate for use in this proceeding are $11,100,000, $208,000, and $171,000, respectively.

Operation and Maintenance Expense

The first area of difference between the Company and the Public Staff is operation and maintenance expense. The difference of $(1,519,000) is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to advertising expense	$ (132)
Adjustment to purchased capacity expense	(1,390)
Removal of 50% of selected officers' compensation	(28)
Removal of cost of community and governmental affairs projects	(10)
Adjustment to common stock issuance expense	41
Total	$(1,519)

The first adjustment made by the Public Staff concerns the appropriate amount of advertising expense. The $(132,000) difference between the parties is itemized as follows:

Item	Amount
Competitive advertising	$(108,000)
Promotional advertising	(11,000)
Image advertising	(13,000)
Total difference	$(132,000)

The advertisements at issue were set forth in Public Staff Chamberlain Rebuttal Cross-Examination Exhibit No. 1. Public Staff witness Maness made an adjustment to remove $108,000 of competitive advertising costs. In calculating his adjustment, witness Maness removed 100% of the costs of the Baby, Degree, and Gas Grill advertisements and 50% of the costs of the Company's Co-Op advertising program. Witness Maness testified that it was appropriate to consider 50% of the costs of Co-Op advertising to be costs of advertising intended in whole or in part to compete with natural gas companies or with other energy providers. Witness Maness stated that it would be inappropriate to require ratepayers to support advertising which included the promotion of electricity over gas, and that he did not think this Commission should send a message to utilities that ratepayers would finance a competitive war between electric and gas companies. Witness Maness further stated that he was

unaware of this Commission taking a position on the preference of either gas or electricity. Witness Maness testified that he had allowed advertising costs associated with ads that promoted the more efficient use of electricity but did not allow ads that promoted the use of electricity over gas.

The Company took the position that the purpose of this type of advertising was to promote energy efficiency and provide information to the Company's customers. On cross-examination, witness Chamberlain acknowledged that the Company is in competition for winter heating with gas companies and that the issue is the energy choice one makes. Furthermore, witness Chamberlain stated that he was unaware that the Commission had disallowed competitive advertising costs in North Carolina Natural Gas Corporation's last general rate case.

The Commission has carefully reviewed Public Staff Chamberlain Rebuttal Cross-Examination Exhibit No. 1 in regard to the competitive advertising costs in question. The Commission agrees with the Public Staff that it is proper to remove from operating revenue deductions advertising that is designed to compete with natural gas companies or with other energy providers. On the other hand, it is also proper to include in the cost of service advertising that is devoted to conservation, reduction of peak demand, and energy efficiency, all of which are permissible under Rules R12-12 and R12-13. Based on its review of the ads, the Commission finds and concludes that as many as one-half of the ads disallowed by the Public Staff for competitive advertising costs do indeed promote conservation, reduction of peak demand, and energy efficiency. Therefore, $54,000 of the Public Staff's recommended disallowance should be included in the Company's operating revenue deductions for purposes of this proceeding.

Witness Maness removed $11,000 of promotional advertising cost. Witness Maness testified that the promo-

tional advertisements were intended to promote the sale of outdoor or night lighting and as such the costs of the ads are not a legitimate cost of providing electric service to ratepayers. Witness Chamberlain took the position that this type of advertising promotes the use of efficient residential outdoor lighting. On cross-examination, witness Chamberlain stated that he was not familiar with the Commission Rules R12-12 and R12-13 which define promotional advertising. Furthermore, witness Chamberlain acknowledged that the "promotional" ads did not provide information to customers about converting from inefficient incandescent bulbs to high efficiency bulbs nor about using motion-sensor lighting that might be less wasteful. Witness Chamberlain also testified that the National Night Out Campaign advertisements were part of the Company's public service or community activities concerning crime prevention.

Based on the foregoing and its review of the advertisements in question, the Commission concludes that the Public Staff adjustment to exclude promotional advertising costs is appropriate. The Commission finds that the Company's promotional advertising is inconsistent with the provisions setting forth the allowable types of advertising in Commission Rules R12-12 and R12-13.

The remaining difference in advertising costs relates to the Public Staff exclusion of $13,000 of image advertising costs. Witness Maness testified that it was the Public Staff's position that image advertising was not a necessary cost for public utilities and therefore those costs should be removed from operating revenue deductions.

Witness Chamberlain testified that the ads that were classified by the Public Staff as image advertising were part of an overall ad campaign to provide information and meet customer needs. When questioned about various ads, such as the sweater recycling ads, witness Chamberlain admitted that the majority of the ads did not

directly address issues of safety or energy efficiency. On cross-examination concerning advertising for the Energy-share program, witness Chamberlain stated that this program was not image advertising but it was advertising consistent with the overall strategy of promoting Company name recognition.

Witness Chamberlain's position throughout his testimony was essentially that each ad was part of the campaign, and if the campaign was valid, then each part was also necessary. How NC Power reacts to its advertising agency's recommendations and how this Commission deals with the advertising costs are two entirely separate issues. The Commission will review each ad pursuant to its Rules.

After a careful review of Public Staff Chamberlain Rebuttal Cross-Examination Exhibit Nos. 1 and 2, the Commission concludes that the Public Staff adjustment is proper and consistent with the Commission's policy concerning image advertising. The Commission finds that the amount of image advertising costs to be removed from the cost of service is $13,000.

The second adjustment to operation and maintenance expense made by the Public Staff is the adjustment recommended by Public Staff witness Powell to the cost of capacity purchased from the Hadson project. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 34-59, the Commission has found this adjustment to be appropriate. Therefore, the Commission concludes that it is appropriate to reduce operation and maintenance expense by $1,390,000 to reflect the removal of unreasonable purchased capacity costs.

The next adjustment made by the Public Staff concerns officers' salaries. Public Staff witness Maness testified that consistent with the adjustments made by the Commission in recent years for other electric utilities, he was recommending an adjustment to charge the stock-

holder 50% of the compensation paid by the Company to those officers whose functions are most closely linked with meeting the demands of the Company's sole common stockholder, Dominion Resources, Inc. Witness Maness indicated that the officers whose compensation he split were as follows:

(1) President/Chief Executive Officer

(2) Chairman of the Board of Directors

(3) President/Chief Executive Officer of Dominion Resources, Inc.

Witness Maness testified that these three individuals are closely linked to meeting the demands of the Company's common shareholder. All three individuals serve on the Vepco Board of Directors, as well as the Dominion Resources, Inc. Board of Directors. The Chairman of the Vepco Board is also Chairman of the Dominion Resources, Inc. Board, as well as of the Boards of Dominion Resources, Inc.'s other subsidiaries, Dominion Capital, Dominion Energy, and Dominion Lands. Witness Maness testified that this adjustment is especially appropriate for Vepco given the nature of Dominion Resources, Inc.'s non-regulated business interests. Witness Maness stated that the interests of Dominion Resources, Inc. as they relate to its non-regulated businesses may not always coincide with the interests of Vepco's retail ratepayers. Witness Maness also testified that the Commission has adopted an adjustment consistent with his approach in each of the seven Duke, CP&L, and Vepco general rate cases decided since November 1984.

Company witness Schools testified that officers' compensation is an appropriate determinant of the cost of service. Witness Schools also testified that the allocation of officers' compensation between Vepco and other subsidaries of Dominion Resources, Inc. (which, according to the testimony of witness Maness, contributed to an increase of 96% in the compensation paid by Vepco to

the officers in question in this proceeding over and above that reflected in the last general rate case proceeding) is based on an Order of the Virginia State Corporation Commission. However, witness Maness pointed out that his adjustment focuses on the level of executive compensation paid by Vepco and testified that the fact that this compensation results from an allocation should not affect the evaluation of whether or not 50% of it should be assigned to the common stockholder. Witness Maness indicated that the adjustment is based on the duties that these officers perform as employees of Vepco, not as officers and employees of Dominion Resources, Inc.

After careful consideration, the Commission concludes that the Public Staff adjustment to exclude 50% of the compensation of the three officers in question is appropriate. The Commission finds that it is reasonable for the Company's common stockholder to bear 50% of the compensation expense of the Company officers whose function is most closely linked with meeting the demands of the stockholder. The Commission notes that this adjustment is consistent with adjustments made in the following 11 electric general rate cases:

> Duke Power Company—Docket No. E-7, Subs 338, 391, 408, and 487; Carolina Power & Light Company—Docket No. E-2, Subs 444, 461, 481, 526, and 537; and, NC Power—Docket No. E-22, Subs 265 and 314.

As it did in the Company's last general rate case, the Commission rejects any contention that this adjustment is inappropriate because some or all of the compensation in question results from an allocation process between the Company, its parent, and/or the parent's other subsidiaries. It is readily apparent that the compensation allocated to Vepco is at an executive level. Consequently, for purposes of evaluating the ratemaking treatment of their Vepco compensation, these individuals

should be treated as officers of Vepco. That they may also receive compensation from the parent company or its other subsidiaries on the basis of activities performed as employees of those entities is irrelevant to the question of whether a portion of their Vepco compensation should be assigned to the common stockholder on the basis of the inherent relationship between stockholders and the top executives of a utility. The Commission is making its adjustment on the basis of the relationship of Dominion Resources, Inc. to Vepco as a stockholder, not on the basis of the relationship of Dominion Resources, Inc. to Vepco as a co-employer of certain individuals. These two relationships are distinct and separate.

The next adjustment to operation and maintenance expense made by the Public Staff is its removal of the cost of community and governmental affairs projects. Public Staff witness Maness testified that these expenses fall in the category of contributions, donations, and other non-utility related items which are not a necessary cost of providing utility service. The Commission agrees that non-utility related items should not be included in cost of service and, consistent with its findings and conclusions regarding charitable contributions discussed elsewhere in this Order, concludes that the Public Staff adjustment to remove $10,000 related to community and government affairs projects from operation and maintenance expense is reasonable and appropriate.

The final Public Staff adjustment to operation and maintenance expense concerns the appropriate treatment of common stock issuance costs. As discussed in the Evidence and Conclusions for Finding of Fact No. 80, the Commission has found the adjustment recommended by Public Staff witness Hinton to be appropriate. Therefore, the Commisison concludes that the Public Staff adjustment to increase operation and maintenance expense by $41,000 to reflect common stock issuance costs is reasonable and appropriate for purposes of this proceeding.

In summary, the Commisison concludes that the level of operation and maintenance expense (other than fuel) under present rates appropriate for use in this proceeding is $75,065,000.

Depreciation and Amortization

The second area of difference between the Company and the Public Staff is depreciation and amortization expense. The difference consists entirely of the Public Staff adjustment to remove the North Anna Unit 3 amortization expense of $1,306,000 (as proposed by the Company) from expense. Public Staff witness Maness testified that because the amortization period established by the Commission for the North Anna Unit 3 abandonment loss will end approximately six months after the date rates become effective in this proceeding, inclusion of the remaining amortization expense in rates would result in a non-representative level of operating revenue deductions. Therefore, witness Maness removed the amortization from expenses. According to witness Maness, his recommended treatment is consistent with the treatment accorded the North Anna Unit 4 amortization by the Commission in the Company's last general rate case, Docket No. E-22, Sub 314.

However, witness Maness testified that it is reasonable in his view to provide the Company an opportunity to recover the remaining unamortized balance by another means. Therefore, he has recommended the establishment of a rider to recover this balance. This rider, based on the remaining unamortized balance of the loss, would expire one year after the date it becomes effective.

Company witness Schools testified that while the Company does not dispute the level of expenses used by witness Maness to calculate the rider, the use of such a rider is not warranted in this case. Witness Schools stated that the collection of North Anna Unit 3 costs throughout the

amortization period has been through base rates, and that the final amortization is a proper component of cost of service which should be collected through base rates, not unnecessarily singled out for separate treatment. Witness Schools also testified that the Company is not aware that the Commission has routinely employed the use of riders for purposes of segregating cost recovery in base rates.

Therefore, the Commission is presented with four options regarding this cost: include the remaining amortization in the cost of service, exclude it entirely from rates, amortize it over a longer period of time, or allow recovery through a rider. The Commission concludes that complete exclusion is not fair to the Company, just as inclusion in ongoing operating revenue deductions would not be fair to ratepayers. Amortization over a longer period of time would provide recovery for the Company, but the Commission does not want to extend the amortization period beyond the ten years ordered if it can be reasonably avoided. Recovery of the remaining cost through a one-year rider provides recovery of the cost and does not necessitate a significant extension of the amortization period. The Commission thus finds that approach to be the most appropriate of the four possibilities. A rider of shorter duration which would terminate exactly at the end of the ten-year amortization period would also achieve the Commission's objectives. However, the Commission believes that a twelve-month rider is a reasonable choice in that it mitigates the immediate increase in the revenue requirement imposed upon the ratepayer relative to a shorter rider and does not significantly extend the recovery period beyond ten years.

Consistent with its decision in Docket No. E-22, Sub 314, regarding the North Anna Unit 4 amortization, the Commission concludes that the remaining partial year's amortization of the North Anna Unit 3 loss should be removed from ongoing operating revenue deductions and

that recovery of the remaining loss should be accomplished through use of a one-year increment rider. The circumstances presented by this rate case are the same as those presented in Docket No. E-22, Sub 314 with regard to the North Anna Unit 4 amortization, in that it is known that the amortization period for the North Anna Unit 3 loss will end very shortly after the rates set in this proceeding go into effect. To set rates which are fair and reasonable, the Commission must strive to determine a representative level of operating revenue deductions. Because the amortization of North Anna Unit 3 ends so soon after the effective date of the rates established in this case, inclusion of the remaining cost in operating revenue deductions would clearly result in a non-representative level of operating revenue deductions.

During the hearing, the Company attempted to differentiate the North Anna Unit 3 treatment proposed by the Public Staff from the treatment accorded the North Anna Unit 4 amortization by the Commission in the Company's last general rate case, noting that the remaining North Anna Unit 4 loss was collected as an offset to a refund of excess deferred taxes (resulting in a net credit) and that the recovery was accomplished through a one-time lump-sum billing. The Commission concludes that the factors set forth by the Company do not substantively differentiate the two treatments. In both cases, the remaining partial year's amortization has been removed from ongoing operating revenue deductions and set for recovery through a special revenue mechanism. That the North Anna Unit 3 recovery is being effected over 12 months rather than one month, as was approved for North Anna Unit 4, amounts to only a matter of timing (i.e. a 12-bill rider rather than a one-bill rider). Likewise, the fact that there is no unrelated credit in this case against which to offset the recovery of the amortization is irrelevant to the question of the appropriate treatment to be given to the amortization. The combination of the

excess deferred tax refund with the North Anna Unit 4 loss in the last general rate case was simply a matter of convenience. The two issues themselves were completely unrelated to each other.

Therefore, the Commission concludes that it is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 3 loss amortization of $1,306,000 from depreciation and amortization expense. Consequently, the level of depreciation and amortization expense appropriate for use in this proceeding is $20,606,000.

The Commission also concludes that it is appropriate and reasonable to establish an increment rider in the amount of 0.066328¢/kWh, to expire one year from the date of this Order, for the purpose of allowing the Company to recover the remaining unamortized North Anna Unit 3 abandonment loss.

Income Taxes

The third area of difference between the Company and the Public Staff is income taxes. The difference of $881,000 is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to North Carolina state income tax surcharge rate	$ (4)
Adjustments related to Public Staff adjustments in other areas	885
Total	$881

The first Public Staff adjustment is its adjustment to the surcharge rate to be applied to North Carolina state income taxes. Public Staff witness Maness testified that he utilized a surcharge rate of 1.5%, the average of the rates for 1993 (2%) and 1994 (1%), as opposed to the

1993 rate of 2% utilized by the Company. In his opinion, use of the average rate is appropriate because the Company does not generally file a rate case annually.

Company witness Schools testified that it is uncertain at this time whether or not the Company will file a rate case in 1993. Witness Schools characterized the Public Staff adjustment as speculative and asserted that it builds into rates an undercollection of the 1993 level of expense. According to witness Schools, the 2% rate, being known and measurable, more accurately reflects the going level in this case.

Company witness Rhodes testified that assuming a reasonable result from this case and barring unforeseen circumstances, it is unlikely that the Company would file another general rate case this year. Additionally, witness Rhodes testified that the Company's last general rate case Order was issued approximately two years ago and that the next to last general rate case occurred about seven years before that one. Witness Schools testified subsequently that the actual decision regarding whether or not to file a case this year has not yet been made and that all of the information necessary to make that decision was not yet available.

With regard to the definition of the "going level in this case," Witness Schools testified that it involved looking essentially at a one-year rate period.

During cross-examination, counsel for the Company asked Public Staff witness Maness whether the change in the rate to 1% in 1994 is a known and measurable change taking place prior to the close of the hearing. Witness Maness replied that the change is known and measurable but would not take place prior to the close of the hearing. Witness Maness compared his treatment of the surcharge to the treatment of rate case expense,

in which an estimated annual level of rate case expense is set based on an estimate of the period of time lapsing between rate cases. Additionally, witness Maness testified that the surcharge adjustment should be based on current law, under which the rate will change to 1% in 1994, and not on the basis of any hypothetical actions the legislature might or might not take.

Witness Maness was also asked if it would be possible to treat the surcharge similarly to his proposed treatment for the North Anna Unit 3 amortization and establish a rider to recover all or a portion of the cost. Witness Maness testified that it would be possible, but that he considered North Anna Unit 3 to be an "exception to the rule," while the surcharge is handled in a more traditional manner. Witness Maness listed three differences between North Anna Unit 3 and the surcharge: the Commission's rationale in developing a ten-year amortization period, the large size of the North Anna Unit 3 cost in relation to the surcharge, and the precedent established by the Commission in the Company's last general rate case.

The Commission concludes that the expense included in this case for the North Carolina state income tax surcharge should be based on an average rate of 1.5%. It is known and measurable under current law that the rate is set at 2% for 1993 and 1% for 1994. The Commission also concludes that utilization of an estimated two-year period between this case and the next general rate case is reasonable, especially given witness Rhodes' testimony and that seven years passed between the Commission's rate case Orders in Docket No. E-22, Sub 273, and in Docket No. E-22, Sub 314, and two years between the Orders in Docket No. E-22, Sub 314 and in this case. The Commission thus finds it appropriate to spread the surtax to be incurred under current law, based on the jurisdictional state income tax expense found reasonable in this case, over the estimated period of time between rate cases of two years. This metholology

is consistent with that adopted by the Commission in such recent general rate cases as North Carolina Natural Gas Corporation (Docket No. G-21, Sub 293) and Duke Power Company (Docket No. E-7, Sub 487).

With regard to the Company's contention that a rider similar to the North Anna Unit 3 rider could be established for the surcharge, the Commission concludes that such a rider is not appropriate for purposes of this proceeding. The Commission has explained elsewhere in this Order that it is appropriate to remove the North Anna Unit 3 amortization from operating revenue deductions and effect its recovery through a temporary rider to be fair to both the Company and the ratepayers. Due to the relatively small size of the surcharge, it is not necessary to remove it from operating revenue deductions to set fair and reasonable rates.

The remaining Public Staff adjustments to income tax expense result from the other Public Staff adjustments to expenses as well as its recommended capital structure, cost rates, and rate base.

The Commission thus concludes based on its findings on rate base, revenues expenses, capital structure, and cost rates that the level of income tax expense under present rates appropriate for use in this proceeding is $8,607,000.

Charitable Contributions

The final area of difference in operating revenue deductions between the Company and the Public Staff is charitable contributions. The difference consists solely of the Public Staff adjustment to remove the charitable contributions of $89,000 (net of tax) included by the Company in operating revenue deductions. Public Staff witness Maness testified that he removed those items specifically identified by the Company in its filing as charitable and educational donations. Witness Maness testified that contributions are not a necessary cost of

providing utility service and that ratepayers should not be required to pay for contributions to charities selected by the Company rather than the ratepayers. Additionally, witness Maness testified that even if the Company's donations are not inconsistent with the public interest, they should not be passed through to the ratepayers in the price of electricity. He stated that nonregulated businesses that make donations have much less control over the price of their goods and services than does the Company.

Company witness Schools testified that the Company continues to support the inclusion of contributions as appropriate costs of service. Witness Schools testified that contributions are necessary in terms of corporate involvement in the community and being a good corporate citizen.

Under cross-examination, witness Schools agreed that he would assume that there would be a fairly wide disparity in the charities to which different ratepayers would contribute. Witness Schools also agreed that a residential ratepayer in Elizabeth City would not have the option of buying electricity from another provider if he disagreed with a charity to which the Company contributes.

Witness Schools testified that if the Company refused to make charitable contributions, it could result in ill-will or additional costs resulting from the refusal to make a particular contribution in the past. Witness Maness testified that he believed the ratepayers are interested in the provision of quality service at a reasonable cost and that by providing that, the Company can do much to maintain the goodwill felt toward it by the ratepayers.

The Commission concludes that the Company's charitable contributions should not be included in the cost of service. It has been a long-standing policy of this Commission to exclude contributions from operating expenses.

Charitable contributions are not a necessary cost of providing electric service.

Therefore, the Commission concludes that the Public Staff adjustment to remove $89,000 of charitable contributions from operating revenue deductions in this proceeding is reasonable and appropriate.

Based upon the Commission's conclusions in this Order, the Commission finds that the level of operating revenue deductions under present rates, excluding fuel expense, appropriate for use in this proceeding is $115,757,000, calculated as follows:

(000's Omitted)

Item	Amount
Operation and maintenance expense	$ 75,065
Depreciation and amortization	20,606
Other taxes	11,100
Income taxes	8,607
Other interest expense	208
Interest on tax deficiencies	171
Total	$115,757

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 75 AND 76

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Carney and Public Staff witness Hinton.

The Company and Public Staff are in agreement with respect to the capital structure and cost rates for long-term debt and preferred stock for use in this proceeding.

Therefore, the Commission finds and concludes that the capital structure and the cost rates for long-term debt and preferred stock appropriate for use herein are as follows:

	Capitalization Ratio %	Cost Rate %
Long-term debt	45.227	8.024
Preferred stock	9.955	5.598
Common equity	44.818	—
Total	100.000	—

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77-82

The evidence for these findings of fact is found in the testimony and exhibits of Company witnesses Avera and Carney and Public Staff witness Hinton.

The Company and Public Staff were not in agreement on the proper investor return requirement for common equity. Company witness Avera recommended that the Commission find 12.0% to 13.0% as the proper range for the cost of equity to the Company excluding any flotation costs. Public Staff witness Hinton recommended that the Commission adopt 11.5% as the cost of common equity for the Company in this proceeding.

In his pre-filed testimony, Company witness Avera employed three different methods in his cost of equity analysis: the constant growth DCF model, the non-constant growth DCF model, and the risk premium method.

In applying the constant growth DCF model, witness Avera studied 19 companies which he believed were comparable in risk to Dominion Resources, Inc., the parent holding company of Vepco. Using the constant growth DCF model, witness Avera determined that the investor return requirement was in the range of 8.9% to 12.22% for Dominion Resources, Inc. and 9.0% to 10.0% for the comparable group. Employing the non-constant growth DCF model, witness Avera estimated that the

cost of equity for Dominion Resources, Inc. ranges from 6.82% to 12.69% and the cost of equity for the comparable group ranges from 8.38% to 12.46%. However, because in witness Avera's judgment the DCF method was producing illogical and unreliable results which violated the risk/return tradeoff, he testified that the results of these models could not always be relied on as a measure of investor's required rate of return.

In conducting his risk premium analysis, witness Avera surveyed the literature and selected published studies which applied seven different analytical approaches. These approaches in general can be categorized as "mechanistic" DCF-derived comparisons, investor surveys, and historical earned returns comparisons. The various studies produced cost of common equity ranges of 11.60% to 15.37% and an average risk premium result of 13.57%.

Witness Avera testified that in his opinion 25 basis points should be added to the "barebones" cost of equity to adjust for flotation costs necessarily incurred when issuing common stock. His final recommendation to the Commission was a range of equity cost rates from 12.25% to 13.25% including this adjustment.

Public Staff witness Hinton employed two different cost of equity methods in his analysis of the investor return requirement for the Company. The first method witness Hinton employed was the constant growth DCF model. He performed a DCF analysis on Dominion Resources, Inc. and on two groups of utilities comparable in risk to Dominion Resources, Inc.—an electric utilities group and a non-electric utilities group. At the hearing, witness Hinton updated his DCF results. However, his conclusion for the cost of equity based upon the DCF results remained at 11.0% to 11.5%.

Witness Hinton also performed a risk premium study based upon a study performed at the Federal Energy Reg-

ulatory Commission (FERC). In his testimony he pointed out the advantages of the FERC approach and noted several criticisms of conventional applications of the risk premium method such as the use of historical data on earned returns dating back to 1926, the use of study results based solely on polling utility stock analysts, and reliance on risk premium studies which themselves display inconclusive and wide ranging results. Witness Hinton's risk premium study, which he updated at the hearing, indicated the Company's cost of equity to be in the range of 11.3% to 12.0%.

Witness Hinton testified that, in reaching his final cost of equity recommendation, he placed more emphasis on his DCF analysis than his risk premium analysis. He concluded that the current investor return requirement to the Company was in the range of 11.0% to 12.0% and recommended that the Commission adopt 11.50% as the investor required return on equity for the Company. Witness Hinton testified that, without evidence of any test year flotation costs associated with a public offering of its common stock and with no evidence of immediate plans of the Company to make such an offering, he could not recommend an adjustment to the return on equity for flotation costs. However, in view of the actual test year expenses associated with the Company's employee and customer stock purchase plans, which were provided by the Company, witness Hinton recommended an adjustment to the cost of service to reflect this ongoing level of expense.

In his pre-filed testimony, witness Hinton also reviewed the testimony of Company witness Avera. Witness Hinton replicated witness Avera's correlation analysis and stated that he disagreed with witness Avera's conclusion that the DCF model has stopped producing logical and reliable results.

Witness Avera also filed rebuttal testimony in this proceeding. In his rebuttal testimony, he criticized wit-

ness Hinton's use of the constant growth DCF model. Witness Avera contended that the current depressed state of the U.S. economy warranted the use of a non-conventional long run growth rate of 5.8%, which produced cost of equity estimates of 12.2% and 12.5% for Dominion Resources, Inc. and his comparable group of electric utilities, respectively. Second, witness Avera sought to rebut witness Hinton's approach to adjustment of risk premiums for changes in interest rates. Witness Avera criticized the Public Staff for understanding the interest rate relationship and for what he said was an improper application of the risk premium method. Third, he criticized witness Hinton's failure to adjust his return recommendation for historical issuance costs. Witness Avera asserted that the true flotation cost adjustment was 25 basis points. Finally, he criticized witness Hinton's failure to account for purchase power commitments in his pre-tax coverage ratio calculations. He contended that if witness Hinton had accounted for the view financial ratings agencies have of purchased power debt equivalents, his return on equity would only produce interest coverage ratios sufficient to support a triple-B bond rating.

During cross-examination, Company witness Avera was questioned on the calculated return on equity derived from his version of the non-constant growth DCF model. Witness Avera maintained that he considered some of the results from the general form DCF to be patently unreasonable. Witness Avera also acknowledged that the results of his non-constant growth DCF varied over a wide range for both Dominion Resources, Inc. and for his comparable companies. Upon further cross-examination, witness Avera acknowledged that the Commission, on page 62 of its Final Order in Docket No. E-22, Sub 314, was correct in its characterization that "the results from the non-constant growth DCF are simply too volatile."

Witness Avera was also cross-examined extensively on his application of the risk premium method in this case.

In response, he testified that the risk premium method does not provide a precise return on equity result. He acknowledged the Order for the prior NC Power rate case in 1991, Docket No. E-22, Sub 314, and the Federal Communications Commission's Order in 1991 which accepted neither his risk premium methodology nor his empirical DCF correlation study.

During cross-examination, witness Avera acknowledged several apparent inconsistencies in and between the risk premium studies which he employed. He acknowledged that Brigham, Shone & Vinson concluded:

> Risk Premiums like interest rates and stock prices are volatile. Our data indicate that it would not be appropriate to estimate the cost of equity by adding the current cost of debt to a risk premium that had been estimated in the past. Current risk premiums should be matched to current interest rates.

The Brigham, Shone & Vinson study also reported finding a significantly positive correlation of interest rates and risk premiums in one period and a negative correlation in another period. Upon further cross-examination, witness Avera acknowledged the findings of another study by Carleton, Chambers and Lakonishok which concluded:

> Using two models, which assume alternative expectations as to the outcome of rate of return regulation, we are unable to find a significant relationship between risk premiums and interest rates.

In his pre-filed testimony, witness Avera cited a risk premium study conducted by Charles A. Benore of the investment advisory firm of Paine Webber, Mitchell Hutchins, Inc. Witness Avera reported this study determined that utility equity risk premiums averaged 4.24% over double-A utility debt costs. He agreed that the Benore study cited in his pre-filed testimony reported that the risk premium for an electric utility not involved in

nuclear construction was approximately 3.17% in 1984 and 2.65% in 1985. On rebuttal cross-examination, witness Avera recalculated the risk premium result of the Benore study with the equity risk premiums of utilities without nuclear construction from the 1984 and 1985 surveys which he reported only marginally reduced the 12 year average equity risk premium from 4.24% to 4.06%. He also acknowledged that Vepco is not currently in the process of building a nuclear power plant.

With respect to his flotation cost adjustment of 25 basis points, witness Avera stated that this adjustment was proper even though the Company has not incurred any flotation costs in seven years and does not plan to incur any flotation costs in the foreseeable future.

On rebuttal, Company witness Carney was extensively cross-examined regarding the reasonableness of witness Avera's 25 basis point flotation cost adjustment to reflect the ongoing level of carrying costs associated with unrecovered past common equity issuance expenses. Attorney General Avera Rebuttal Cross-Examination Exhibit No. 2 showed that a 25 basis point adjustment to the Company's return on equity would, on a system-wide basis, result in increased revenues of approximately $15.8 million to the Company. Witness Carney acknowledged that in the last NC Power rate case the Commission awarded a 0.02% increase in the cost of equity to recover a representative level of common equity flotation costs.

Public Staff witness Hinton was cross-examined extensively on the assumptions used in deriving the constant growth DCF model and its relationship to the non-constant growth DCF model. He stated that the difference in the two models was that the non-constant growth model required an estimate of the stock price at a particular point in time whereas the constant growth DCF required an estimate of the growth rate in dividends to infinity. Witness Hinton stated that it is very difficult to

predict a stock price at a certain point in the future due to the daily market changes and that this aspect of the non-constant growth model increases the method's difficulty and unreliability.

Witness Hinton also answered several questions concerning the risk premium method in general. He testified that the historical risk premium approach can be easily manipulated depending on the time period selected. Upon cross-examination, he responded that the risk premiums studies used by witness Avera demonstrated inconclusive results, especially in the manner in which risk premiums and interest rates are related. He pointed out that some studies report a positive relationship while others report a negative relationship. He further testified that an obvious bias exists when a study utilizes a poll of stock analysts who also perform roles in selling or issuing that very common stock.

Witness Hinton pointed out several distinct advantages of the FERC approach in calculating a risk premium result over other risk premium studies, including the contemporaneous comparison of debt cost and equity costs specific to each utility, the use of current risk premiums over historical risk premiums, and the ability to observe the actual data used. During cross-examination, witness Hinton was asked several questions regarding his use of the FERC risk premium study which compares a utility's authorized returns on equity with its bond cost. He testified that the intent of the study was to measure the additional rate of return investors require to invest in a given utility's equity over its bonds. He was also cross-examined on the bond cost calculation for the Company. He testified that the bond cost calculation was in accord with the FERC study and that, at the time he filed the testimony, the bond cost calculation for the Company was equal to the 8.6% yield on the A-rated bond index for November 1992, as reported in Moody's Bond survey.

Witness Hinton also stated that, in view of the inherent problems associated with any cost of equity method that is largely dependent on bond yields, he gave more emphasis to, and had more confidence in, his DCF results. He testified that today's economic environment differs significantly from prior years, and the lower current DCF results indicate that investors are requiring a lower equity return for utility investments.

The determination of the fair rate of return for the Company is of great importance and must be made with great care because the return allowed will have an immediate impact on the Company, its stockholders, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed, it must balance the interests of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4)

> . . . as will enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and its existing investors.

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b)

> . . . supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of

the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States.

State ex rel. Utilities Comm. v. *Duke Power Co.*, 285 N.C. 377, 388, 206 S.E. 2d 269, 276 (1974).

The Commission is mindful that its conclusion of the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. *State ex rel. Utilities Commission* v. *Public Staff*, 322 N.C. 689, 699, 370 S.E. 2d 567, 573 (1988). Based upon the evidence in the record, the Commission concludes:

(1) *The proper capital cost rates are 8.024% and 5.598% for long-term debt and preferred stock, respectively.* The Company and Public Staff agreed that these cost rates are proper to employ in conjunction with the Company's September 30, 1992, capital structure. The Commission agrees with the Public Staff and the Company that these cost rates are proper to employ for purposes of this proceeding.

(2) *Company witness Avera's version of the general form DCF model and risk premium method as applied in this case should be accorded only minimal weight for purposes of this proceeding.* The results calculated from the non-constant growth DCF model are simply too volatile. The Commission also notes that witness Avera testified that "the general form DCF should not be heavily relied on."

The risk premium method as applied by witness Avera in this case is too easily manipulated. Evidence in the record showed there was a specific risk premium difference between utilities with and without nuclear construction programs. His pre-filed testimony failed to consider this risk premium difference and the Commission is not convinced that his adjustment to reflect nuclear construction programs is adequate or proper. Witness Avera's historical

risk premium analysis also failed to consider that current economic conditions are vastly different from the economic conditions that prevailed from 1926 to 1987. The Commission also finds that minimal weight should be accorded to his risk premium results because the academic studies used to determine the relationship of interest rates and risk premiums are inconclusive.

Evidence was presented that other regulatory agencies have rejected the use of the risk premium studies cited by witness Avera as supporting his cost of equity recommendation. The Commission dealt with this issue in the February 14, 1991, Order in the last NC Power case, Docket No. E-22, Sub 314, and now reaches the same conclusion: that minimal weight should be given to witness Avera's general form DCF and his risk premium methods.

Witness Avera's pre-filed constant growth DCF conclusions ranged from 8.9% to 10.4% for Dominion Resources, Inc. and between 9.0% and 10.0% for his comparable group. He also filed rebuttal testimony that presented a revised constant growth DCF model that combined a long-term growth adjustment for the U.S. economy and a growth adjustment for the Company, which produced cost of equity estimates of 12.2% and 12.7%.

The Commission is not convinced that the current state of the economy warrants incorporating two growth factors in the constant growth DCF. Therefore, the Commission gives minimal weight to witness Avera's non-conventional DCF growth adjustment.

(3) *The constant growth DCF model and the FERC risk premium approach as employed by witness Hinton should be given the greatest weight for purposes of determining the cost of equity capital in this case.*

Public Staff witness Hinton employed the constant growth DCF model which produced a cost of equity recommendation in the range of 11.0% to 11.5%.

The Commission does not agree with witness Avera's assertion that a stock's earnings, dividends, and book value must grow in lock-step for the constant-growth DCF model to be valid and useful for ratemaking purposes. Although the estimation of the prospective growth for these rates is necessarily problematic and requires a certain amount of subjective judgment, it appears to the Commission that witness Avera's non-constant growth DCF model is far more subjective.

Public Staff witness Hinton also utilized the FERC risk premium approach, which produced cost of equity estimates for Dominion Resources, Inc. in the range of 11.3% to 12.0%, based on a risk premium range of 280 to 350 basis points. The Commission finds no reason to believe that the required risk premium for the Company is in the significantly higher range recommended by witness Avera. The Commission further notes that, based upon the last NC Power Order, the FERC risk premium result was 2.86%, which is within the risk premium range recommended by witness Hinton.

The Commission notes that the FERC approach focuses on investors' required returns on electric utility investment, as opposed to the conventional risk premimum methods that analyze earned returns during economic conditions not comparable with today. The Commission, for purposes of this proceeding, finds that the constant growth DCF model and the FERC risk premium approach produce consistent, reasonable, and reliable estimates of the cost of equity and that these methodologies should be given the greatest weight for purposes of determining the cost of equity in this proceeding.

(4) *The investor return requirement to the Company is 11.8%.* In reaching this conclusion, the Commission has placed the greatest weight on estimates of the cost of common equity derived by use of Mr. Hinton's constant growth DCF model and, in particular, the FERC risk premium approach. Based upon those studies, Public Staff witness Hinton testified that the current investor return requirement to the Company is in the range of 11% to 12%. We conclude that a rate of return on common equity of 11.8%, which is well within the range testified to by Public Staff witness Hinton, is reasonable and appropriate in this case. In deciding to authorize a rate of return of 11.8% on common equity, the Commission has placed slightly greater weight and emphasis on the FERC risk premium approach than the constant growth DCF results. Only minimal weight has been accorded the evidence relating to the risk premium methods and the non-constant growth DCF model contained in the Company's testimony. Based upon the entire evidence of record, the Commission finds and concludes that the proper common equity investor return requirement for purposes of this proceeding is 11.8%.

(5) *The adjustment to allow the Company to recover test year common equity issuance expenses associated with the Company's stock purchase plans, as recommended by Public Staff witness Hinton, is appropriate.* This adjustment will allow the Company to recover a reasonable and representative test year level of issuance expenses for common equity for reasons stated by witness Hinton. This inclusion of issuance expenses in the test-year cost of service reflects an ongoing level of expenses associated with the Company's employee and customer stock purchase plans.

The Commission rejects witness Avera's 25 basis point flotation cost adjustment to the cost of equity

and finds no support for witness Carney's testimony that the Company has never collected past flotation costs. The Commission finds witness Avera's 25 basis point recommendation to be excessive and without support in the evidence of record, a factor of particular importance in view of the Supreme Court's holding that such evidence is essential. *State ex rel. Utilities Commission* v. *Public Staff*, 331 N.C. 215, 415 S.E. 2d 354 (1992). The Commission finds that the Company has incurred a fairly constant level of common stock issuance expenses for over seven years and concludes that the recommendation by witness Hinton is reasonable and supported by evidence of record.

(6) *The overall fair rate of return which the Company should be allowed the opportunity to earn on its rate base is 9.48%.* Based upon the Commission's findings with respect to the proper capital structure and the appropriate cost rates for each component of capital reflected in the capital structure, the Commission finds and concludes that the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 9.48%.

The Commission has also considered the question of the treatment of purchase power agreements as debt and the consequent potential risk to the bond rating of the Company. The Commission notes that its role is not that of a rating agency and that it must consider factors other than those considered by these agencies. The question of the proper treatment of these agreements is by no means closed. The Commission believes that as experience is gained, the various rating agencies may reconsider their treatment of these agreements. The Commission concludes that for purposes of regulation, these agreements should not be considered debt equivalents and that the interest rate coverage resulting from our decision in this matter is adequate. In this regard the

Commission agrees with the decision of the California Public Utilities Commission in *re Application of Pacific Gas and Electric Company,* Decision No. 92-11-047, which contains an extensive analysis of this issue. The Commission also notes that in his December 20, 1991, letter, Thomas E. Capps, President and Chief Executive Officer of Dominion Resources, Inc., argues that the net financial risk to the Company has not been increased by its purchased power program and that a procedure for full and timely recovery through rates is in place and working well.

It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witness, to draw inferences from the facts, and to appraise conflicting evidence. *State ex rel. Utilities Commission* v. *Duke Power Company,* 305 N.C. 1, 287 S.E. 2d 786 (1982); *Commissioner of Insurance* v. *North Carolina Rate Bureau,* 300 N.C. 381, 269 S.E. 2d 547 (1980). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not *res judicata* in succeeding cases. *State ex rel. Utilities Commission* v. *Duke Power Company,* 285 N.C. 377, 395, 206 S.E. 2d 269, 281 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations that vary from case to case." *State ex rel. Utilities Commission* v. *Public Staff,* 322 N.C. 689, 697, 370 S.E. 2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented and its weight and credibility in each case.

The Commission cannot guarantee that NC Power will, in fact, achieve the levels of return on rate base and common equity found to be just and reasonable in this Order. Indeed, the Commission would not guarantee the authorized rate of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds and concludes that the rate of return approved in this Order will afford the Company a reasonable opportunity to earn a reasonable return for its stockholder while providing adequate and economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The Comission has previously discussed its findings and conclusions regarding the fair rate of return which the Company should be afforded an opportunity to earn.

The following schedules summarize the gross revenue (excluding fuel revenue) and the rate of return which the Company should have a reasonable opportunity to achieve based upon the Commission's decisions in this case. These schedules, illustrating the Company's gross revenue requirement (excluding fuel revenue), incorporate the findings and conclusions made by the Commission. As reflected in Schedule I, the Company should be authorized to increase its annual level of non-fuel revenue by $10,642,000 based upon the adjusted test year level of operations.

SCHEDULE I

NORTH CAROLINA POWER

North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF OPERATING INCOME [3]
Twelve Months Ended December 31, 1991
(000's Omitted)

	Present Rates	Approved Increase	Approved Rates
Operating revenue	$144,377	$10,642	$155,019
Operating revenue deductions:			
Operation & maintenance expense	75,065	30	75,095
Depreciation & amortization	20,606	—	20,606
Other taxes	11,100	342	11,442
Income taxes	8,607	4,038	12,645
Interest on customer deposits	208	—	208
Interest on tax deficiencies	171	—	171
Total operating revenue deductions	$115,757	$ 4,410	$120,167
Net operating income	$ 28,620	$ 6,232	$ 34,852

[3] As noted elsewhere herein, this schedule does not reflect fuel revenues and associated-fuel expenses. Based upon the test-year level of operations, the proper level of fuel revenue and fuel-related expenses for use herein, after giving effect to the Commission's approved increase, is $30,007,000 (including gross receipts tax).

SCHEDULE II

NORTH CAROLINA POWER

North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Amount
Investment in electric plant:	
Electric plant in service including nuclear fuel	$598,046
Accumulated depreciation	(166,889)
Accumulated amortization of nuclear fuel	(36,842)
Accumulated deferred income taxes	(37,101)
Net investment in electric plant	357,214
Allowance for working capital:	
Materials and supplies	13,090
Cash working capital	(2,458)
Total allowance for working capital	10,632
Other cost-free capital	(15)
Rate base	$367,831
Rates of Return:	
Present rates	7.78%
Approved rates	9.48%

SCHEDULE III

NORTH CAROLINA POWER

North Carolina Retail Operations
Docket No. E-22, Sub 333
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1991
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
	Present Rates—Original Cost Rate Base			
Long-term debt	45.227%	$166,359	8.024%	$13,349
Preferred stock	9.955%	36,618	5.598%	2,050
Common equity	44.818%	164,854	8.020%	13,221
Total	100.000%	$367,831	—	$28,620
	Approved Rates—Original Cost Rate Base			
Long-term debt	45.227%	$166,359	8.024%	$13,349
Preferred stock	9.955%	36,618	5.598%	2,050
Common equity	44.818%	164,854	11.800%	19,453
Total	100.000%	$367,831	—	$34,852

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 84

Company witness Evans recommended that the basic revenue increase should be spread among the individual customer classes in such a way that the individual class rates of return move toward plus or minus 10% of the overall jurisdictional rate of return. He recommended that the Small General Service (SGS) class and the Outdoor Lighting Service (LITE) class be increased at the overall rate of increase. He recommended that the Residential Service (RES) class be increased approximately 1.2 times the overall rate of increase in order to move its low rate of return up closer to the overall rate of return. He also recommended that the Large General Service

(LGS) class and the Traffic Lighting Service (Traffic) class receive the remaining revenue increase in order to move their high rates of return down closer to the overall rate of return. The Commission estimates that the resulting increase for the LGS class and the Traffic class would be less than 0.8 times the overall rate of return.

Public Staff witness Turner recommended that the RES class should be increased approximately 1.07 times the overall rate of increase; that the SGS class should be increased approximately 0.9 times the overall rate of increase; that the LGS class should be increased approximately 0.98 times the overall rate of increase; that the LITE class should be increased approximately 0.53 times the overall rate of increase; and that the Traffic class should be increased approximately 0.92 times the overall rate of increase. The Public Staff presented a schedule of rate increases and rates of return based on the SWPA cost allocation method which indicated that its proposed rate of increase for each class would produce a rate of return for each class that is closer to the overall rate of return.

CIGFUR witness Phillips recomemnded that the maximum increase allowed by the Commission for the LGS class should be the rate of increase proposed for the LGS class by NC Power even if the SWPA cost allocation method is adopted. He also recommended that if the SWPA method is adopted, approximately $810,000 additional revenues should be shifted from the LGS class to the RES class in order to account for non-symmetrical treatment of fuel costs versus fixed costs in the allocation process.

CUCA recommended that the rates of increase for each customer class be sufficient to move the rates of return for each class at least one-third of the way toward equal rates of return, provided no class receives more than a 20% increase.

The Commission estimates that increasing the RES class by 1.125 times the overal rate of increase will move the RES class rate of return approximately one-fourth of the way toward equalized rates of return. The Commission also estimates that increasing the LGS class by 0.875 times the overall rate of increase will move the LGS class rate of return approximately one fourth of the way toward equalized rates of return. The estimates are based on rates of return produced by the SWPA allocation method.

The Commission concludes that the RES class should be increased 1.125 times the overall rate of increase, the LGS class should be increased 0.875 times the overall rate of increase, and the remaining classes should be increased 1.0 times the overall rate of increase. Such increases will produce rates of return for each rate class respectively that are within 10% plus or minus of the overall rate of return, and they will produce rates of return for each rate class respectively that are closer to equalized rates of return than they were before the increases.

The per books cost of service study (SWPA method) by NC Power indicated that the rate of return for the Traffic class was considerably higher than the overall rate of return, whereas the comparable study based on adjusted revenues and expenses presented by the Public Staff indicated that the rate of return for the Traffic class was approximately the same as the overall rate of return. The Traffic class is a new class established in this proceeding, and the total revenues and expenses attributable to the class are so small that the various accounting adjustments made in this proceeding could have a disproportionate impact on the cost of service study results for the Traffic class. Therefore, out of an abundance of caution, the Commission chooses to increase the Traffic class at 1.0 times the overall rate of increase.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 85

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness Turner. The Company proposed to increase the current residential summer/winter rate differential to 1.0¢/kWh from 0.51¢/kWh, and has based its proposal on the results of a study using forecasted summer and winter peak loads and the Company's capacity expansion model and long-range planning model. The Company's study supports a summer/winter rate differential of 1.9¢/kWh.

Public Staff witness Turner stated that pricing in North Carolina should be based on an embedded cost-of-service study and that North Carolina is required to base the revenue requirement on a historical test year. He contended that forecasted information is by definition not accurate, and he pointed out that the Company's study supporting the 1.9¢ summer/winter rate differential is based on forecasted summer and winter peaks and on future-looking econometric models. He recommended that the Commission hold the rate differential at its current level until the Company submits an embedded cost-of-service study that differentiates costs between the summer and non-summer periods. In addition, he recommended that any such study should also show seasonal cost differentials for both residential and nonresidential customer classes since the Company has summer/winter rate differentials for its non-residential rate schedules also.

Company witness Evans testified that the summer/winter rate differential had been an effective tool in controlling the residential and system summer peak loads and thereby reducing additional generation requirements. He stated that the summer/winter rate differential strategy is a significant reason why the gap between the Company's summer and winter peak loads is narrowing, and that the

narrowing gap results in a more efficient generation system with lower overall customer rates.

Witness Evans testified that he had no dispute with the Public Staff position that revenue requirements in North Carolina should be based on an embedded cost of service study for a historical test period. Nevertheless, he disagreed that individual rate structures should always reflect embedded cost characteristics. He indicated that projected future peak loads are critical from a resource planning perspective, and that such projected future loads should be reflected in the summer/winter rate differentials.

Witness Evans agreed that the Company should address the summer/winter rate differentials for non-residential customers as well as for residential customers. However, the Company elected to focus on the seasonal rate differential for the residential class of customers in this proceeding because it is the most weather sensitive class and presents the greatest opportunity to achieve load management objectives through seasonal pricing. He also testified that it is unlikely that an embedded cost study of seasonal differences in costs would support the proposed summer/winter differentials.

The Commission concludes that the 1.0¢/kWh summer/winter rate differential for residential customers should be approved. The differential seems to achieve generally accepted load management objectives, and it is based on a detailed study performed by the Company, although not an embedded cost study. The Commission anticipates that the Company will perform comparable studies of seasonal cost differentials for non-residential customers for presentation in future proceedings, and that such studies will be at least as detailed as the current ones.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 86

Public Staff witness Turner recommended moving the basic customer charge for residential service closer to actual cost, offset by a corresponding reduction in the energy charge for the service. The Company did not oppose his recommendation, and no other party addressed the proposal.

Witness Turner stated that the basic customer charge proposed by the Company is significantly below cost and should be increased in such a manner as to bring the charge closer to cost. The Company proposed to increase the basic customer charge to $8.50 per month from $7.16. Its cost-of-service study indicates the basic customer charge should be within a range of $15.40 to $15.60 per month based on the Company's proposed rates. Witness Turner recommended that the customer charge be increased to $9.50 per month.

Based on the Company's proposed rates, a typical residential customer with usage of 1,000 kWh per month will have an average percentage increase of 18.47% during the summer and 13.41% during the winter if the per month basic customer charge is raised to $9.50 as proposed by the Public Staff. In comparison, the percentage change for the typical customer based on the basic customer charge of $8.50 as proposed by the Company would be 18.52% and 13.5% during the summer and winter periods, respectively.

Based on the foregoing evidence, the Commission concludes that the residential basic customer charge should be increased to $9.50 per month.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 87-91

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans. Witness Evans testified that the embedded cost of distribu-

tion plant is approximately $916 per residential customer, and that the $916 per customer is reflected in current residential rates. However, the Company is currently investing approximately $2,103 per residential customer in new distribution plant for new residential customers, which results in approximately $1.8 million per year additional plant investment which must be absorbed by all residential customers, not just new customers.

Witness Evans testified that the proposed new line extension plan will require up-front payments for new residential services more frequently. The new plan will continue to require up-front payments for new non-residential services, and such up-front payments will also be more frequent. He estimated that the new plan will recover $1 million per year more from new residential customers and approximately $75,000 per year more from new non-residential customers.

Witness Evans testified that the proposed new line extension plan will continue to require up-front payments from new customers based on a revenue test, but that criteria for the revenue test would be revised in various ways in order to allow a more complete recovery of the investment required for new distribution plant. The more complete recovery of investment in new plant would help delay future general rate increases. He also indicated that the proposed new plan would have some influence over the choice of energy suppliers by prospective customers, but insisted that the plan was not designed to promote one energy source over another.

Witness Evans described the transition process from the current line extension plan to the proposed new plan, and indicated that the Company was requesting 90 days after approval of the plan before making the revisions effective in order to have time to inform its customers of the changes in the plan.

No party to the proceeding opposed the proposed new line extension plan. However, the Company stipulated

with the Public Staff during the hearing on revised language for the line extension plan that would permit a residential customer to request overhead construction rather than underground construction, and that would permit costs for the line extension being determined based on overhead construction costs rather than the more expensive underground construction costs. The Commission is aware that underground line extensions are currently the preferred method of construction for most new residential dwellings; however, overhead line extensions were recognized as the standard method of service connections for many years.

The Commission is of the opinion that the proposal by the Company to recognize underground construction costs coupled with a revenue test applied to these construction costs is an acceptable method of ensuring that the specific costs imposed by new customers on the system are compatible with the revenue contribution these customers are making to the system. Nevertheless, the Commission finds it appropriate for customers who so desire to continue to receive overhead line extensions, and for the construction costs applied in these instances to the corresponding revenue credit to be determined on a case-specific basis. This determination is consistent with the language agreed to by the Company and the Public Staff and introduced as evidence during the cross-examination of Company witness Evans in this proceeding.

The Commission concludes that the proposed new Line Extension Plan, as modified during the hearing, is appropriate and should be approved to become effective 90 days after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 92-95

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness McLawhorn.

Witness McLawhorn testified that the Company should upgrade the thermal standards used to qualify new residential customers for the Residential Conservation Reduction (RCR) so that the benefits derived over and above the requirements of the new North Carolina Building Code to be effective April 15, 1993, are similar to the benefits derived currently. Witness McLawhorn stated that without these changes, new customers would be receiving a rate discount for merely doing what is required by law. Company witness Evans agreed and indicated that the Company would be filing updated standards for Commission approval prior to the effective date of the new building code.

The Commission recognizes the benefits to be derived from DSM programs which ensure a greater level of energy efficiency; however, any incentives paid by the utility to its customers for participation in these programs should be commensurate with the level of benefits received. Therefore, the Commission is of the opinion that the RCR standards applied to new customers should be upgraded so that the benefits over the new building code requirements are maintained at a level comparable to the current benefits.

To this end, the Company should file revised standards before the April 15, 1993, effective date of the new code for Commission approval as agreed to by witness Evans. This filing should include a comparison of the current standards versus the current building code with the new revised standards versus the new building code, along with a quantification of the resulting benefits in each case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 96

The evidence for this finding of fact is found in the testimony of Company witness Evans and CIGFUR witness Phillips.

Witness Evans testified that since the introduction of Schedule 6C, the Company has implemented several provisions to assist the customer in participating in this program. For example, the Company has implemented a provision to allow one curtailment request per season to be excluded in determining compliance (i.e., one waiver per season); the time period from notification until the customer must reduce load has been extended from 10 minutes to 30 minutes; and the potential curtailment period in the summer was reduced from a 12-hour window to a 7-hour window, while in the winter, this window was reduced from 16 hours to one of two five-hour windows (or a total of 5 hours per day). He testified however, that for the Company to offer a cost-effective curtailable rate, the program must be designed with provisions that provide comparable value to a supply-side option. Often the peak hour in the winter occurs in the morning, but there is also need for load management in the late afternoon and early evening hours on extreme weather days. The curtailable rate must include both five-hour windows (for a total of 10 hours per day) if the rate is to be cost effective. A supply-side option such as a combustion turbine would be available to meet both the morning and afternoon peaks.

Witness Evans noted that if the Company elects to request a curtailment in both the morning and the afternoon of the same day, each curtailment will count as a separate request toward the maximum allowable 13 requests per winter season. Accordingly, he stated, this provision would not be overly burdensome to the customer, yet would provide the Company with the means to best manage its seasonal peaks and provide for a cost-effective demand-side program.

CIGFUR witness Phillips opposed the change and recommended that the Commission reject it. He stated that a customer should not be obligated to more than one curtailment per day, consistent with past practice. In his opinion, the proposal would be overly burdensome

and disruptive to customer operations and should not be allowed.

The Commission concludes that the proposed change is reasonable and should not be overly burdensome on customers. The Commission is mindful of the fact that these are voluntary rates, and that the Company has already made a number of modifications to the rates to resolve past difficulties. Therefore, the Commission concludes that the proposed modification to rate Schedule 6C, Schedule SG, and Schedule CS to allow the Company to request two curtailments per day during the winter season is appropriate and should be allowed.

The Commission is also of the opinion that the Company should file a report with the Commission approximately 12 months after the date of this Order describing the number of customers added and lost from the curtailable rates described herein since the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 97

In addition to the specific modifications discussed elsewhere herein, the Company proposes various miscellaneous rate changes, administrative changes and clarifications in its rate schedules which are unopposed by any party.

Highlights of such changes include the following:

(a) Add new rate schedule 5C for cotton gin service;

(b) Add new rate schedule 30T for traffic light service and delete traffic lights from municipal rate schedule 30;

(c) Add Christmas Eve as an off-peak holiday on all TOU rate schedules;

(d) Revise the definition of on-peak hours applicable to Power Supply Demand on TOU rate schedule 5P and 6P;

(e) Revise the SEER rating for heat pumps from 8.7 to 10.0 in order for multi-family or single family homes to qualify for the Residential Conservation Reduction; and

(f) Add provisions allowing installation of new mercury vapor lighting for government facilities.

The Commission concludes that the rate schedules proposed by the Company are reasonable and should be approved as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 98 AND 99

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness Turner. The Company proposed to change the conditions under which it will deliver electric service. Currently, the Company reserves the right to require the applicant to establish that he is the owner or bona fide lessee of the premises and to execute an application for service or the most current "Agreement for the Purchase of Electricty" on file with the Commission. The change proposed by the Company would require all owners and bona fide lessees to apply jointly for service. Witness Turner recommended that no change be made in the current requirement.

Witness Turner expressed the opinion that the proposal is an unduly cumbersome method of receiving applications for electric service and goes beyond usual conditions for service. He further stated that, while the purpose of the revision is to provide the Company with an additional resource in recovering unpaid bills, the Company did not support the proposal with documentation showing the magnitude of the problem nor does it state the conditions under which the Company would impose this requirement. As the language stands, it would be left as a discretionary decision of the Company. He

stated his opinion that the Company's present requirement for customer identification and a deposit is sufficient.

On cross-examination, witness Evans stated the Company would not contest the Public Staff's opposition and would withdraw the proposed change at this time. Based on the foregoing evidence, the Commission concludes that the changes proposed by the Company to paragraph II.A.1 of the Company's Terms and Conditions for the delivery of electric service rules and regulations should not be approved.

In addition to the specific modifications discussed elsewhere herein, the Company proposes various miscellaneous rate changes, administrative changes and clarifications in its terms and conditions of service which are unopposed by any party.

Highlights of such changes include revised service charges as follows:

Service connections	From	$23.74 to $20.55
Bad check charge	From	$12.71 to $14.47
Trouble call charge if customer's responsibility	From	$33.75 to $25.73
Reconnect charge during normal hours	From	$29.40 to $33.80
Reconnect charge after normal hours	From	$45.00 to $73.83

Other highlights include an increase in the minimum charge for additional meters for an individual customer from $0.97 to $18.25; and revision of the extra facilities charge in order to reflect the rate of return.

The Commission concludes that the terms and conditions of service proposed by the Company are reasonable and should be approved as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 100

The evidence supporting this finding of fact is contained in the record in this case. G.S. 62-133.2 provides that the Commission shall hold a hearing within 12 months after an electric utility's last general rate case Order to determine whether an increment or decrement rider is required ". . . to reflect actual changes in the cost of fuel and the fuel cost component of purchased power over or under base rates established in the last preceding general rate case." G.S. 62-133.2 further provides that additional hearings shall be held on an annual basis but only one hearing for each such utility may be held within 12 months of the last general rate case. G.S. 62-133.2(c) sets out the verified, annualized information and data which the utility is required to furnish to the Commission at the hearing for a historic 12-month period" . . . in such form and detail as the Commission may require . . ." Pursuant to Rule R8-55, the Commission has prescribed the 12-month period ending June 30, 1992, as the test period for the fuel proceeding.

The Company indicated in its July 31, 1992 Application for a General Increase in Rates (Docket No. E-22, Sub 333) that it intended to update its calculations of fuel cost in the general rate case for the 12-month period ended June 30, 1992, consistent with the Company's annual fuel clause test period. On September 30, 1992, NC Power filed a Motion for Consolidation of Hearings in which it moved to consolidate hearings in its general rate case and its fuel clause proceeding, Docket No. E-22, Subs 333 and 335, which motion was granted by the Commission in its October 5, 1992 Order. The Commission concludes that the appropriate test period for the base fuel factor determination is the 12-month period ending June 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 101-103

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witnesses Ross and Evans and Public Staff witness Lam.

Company witnesses Evans and Ross (Mr. Ross adopted the testimony of Daniel J. Green) and Public Staff witness Lam testified with regard to the July 1, 1991, to June 30, 1992, test period sales, test period generation, and normalized nuclear capacity factor. Company witnesses Ross and Evans testified that the July 1, 1991, to June 30, 1992, test period levels of sales and generation were 57,794,906 mWh and 61,448,089 mWh, respectively. The 57,794,906 mWh of test period sales reflects 57,825,522 mWh of actual sales as reported in Rule R8-55(d)(1), reduced by 30,616 mWh to reflect that Old Dominion Electric Cooperative sales are booked at production level. The test period per book system generation includes various energy generations as follows:

	mWh
Coal	25,992,366
Nuclear	22,978,300
Heavy Oil	1,912,993
Natural Gas	87,836
Internal Combustion	1,413,808
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,268,968
Other	5,234,861
Interruptible Sales	(2,551,212)

Public Staff witness Lam accepted the levels of sales and generation as proposed by the Company for use in his fuel computation.

Company witness Ross testified that the Company achieved a system nuclear capacity factor of 77.7% for

the July 1, 1991, to June 30, 1992, test period. Witness Ross normalized the system nuclear capacity factor to a level of 69.24%, which is the latest North American Electric Reliability Council's (NERC) five-year nuclear capacity factor. Witness Lam agreed that the nuclear capacity factor of 77.7% as achieved by the Company was abnormally high and should be normalized to the latest NERC five-year pressurized water reactor average of 69.24%. No other party offered testimony on the normalized nuclear capacity factor. In the absence of evidence presented to the contrary, the Commission concludes that the July 1, 1991, to June 30, 1992, test period levels of sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 69.24% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 104

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Ross and Green and Public Staff witness Lam.

Company witness Ross and Public Staff witness Lam testified regarding normalized generation. In Docket No. E-22, Sub 333 (rate case proceeding), witness Ross proposed a normalized generation using a historical level of generation based on 12 months ended December 31, 1991. In Docket No. E-22, Sub 335 (fuel clause proceeding), witness Ross proposed a normalized generation based on the 12-month test period ended June 30, 1992. The Public Staff accepted the Company's proposed normalized generation based on the 12-month test period ended June 30, 1992, as being appropriate for use in determining the fuel factor.

The Commission concludes that normalized generation should be based on the 12-month test period ended June 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 105

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

Witness Evans testified that consistent with Commission Rule R8-55(d)(2) the Company's system sales data for the 12-month period ending June 30, 1992, was adjusted by jurisdiction for weather normalization, customer growth, and increased usage. Witness Evans adjusted total Company retail sales by 818,572 mWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 280,695 mWh, 183,088 mWh and 354,789 mWh, respectively. The Public Staff reviewed and accepted these adjustments.

Based on the foregoing evidence, the Commission concludes that the adjustments due to customer growth, increased usage, and weather normalization of 280,695 mWh, 183,088 mWh, and 354,789 mWh, respectively, are reasonable and appropriate adjustments for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 106

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Ross and Evans and Public Staff witness Lam.

Company witness Evans and Public Staff witness Lam addressed the adjusted level of generation. Witness Evans presented an adjustment to per book mWh generation for the 12-month period ended June 30, 1992, due to

weather normalization, customer growth, and increased usage of 861,066 mWh, to arrive at witness Ross's adjusted generation level of 62,309,169 mWh.

The Public Staff accepted witness Evans' adjustment to per book mWh generation for the 12-month period ended June 30, 1992, due to weather normalization, customer growth, and increased usage. Witness Lam accepted witness Ross's generation level of 62,309,169 mWh which includes various energy generations as follows:

	mWh
Coal	28,130,404
Nuclear	20,474,196
Heavy Oil	2,070,346
Natural Gas	95,061
Internal Combustion	1,530,090
Hydro	2,302,348
Pumped Storage	(2,192,202)
Purchase & Interchange	
NUG	6,784,633
Other	5,665,469
Interruptible Sales	(2,551,212)

Based on the foregoing evidence and with no other evidence to the contrary, the Commission concludes that the adjustment of 861,066 mWh is reasonable and appropriate for use in this proceeding, and that the resultant adjusted fuel generation level of 62,309,169 mWh is also reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 107-109

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Ross and Public Staff witness Lam.

Witness Green's prefiled testimony of September 11, 1992, which was adopted by witness Ross, contained fuel

prices as follows: (1) coal price of $14.27/mWh; (2) nuclear fuel price of $4.69/mWh; (3) heavy oil price of $24.90/mWh; (4) natural gas price of $30.59/mWh; (5) internal combustion turbine price of $18.50/mWh; (6) other purchased and interchanged power price of $17.23/mWh; and (7) hydro, pumped storage, and non-utility generation at a zero fuel price.

Witness Lam, in his testimony, accepted witness Ross's fuel prices for heavy oil ($24.90/mWh), natural gas ($30.59/mWh), and hydro, pumped storage, and NUG generation (zero fuel price) and total fuel cost of interruptible sales of $28,446,000. However, witness Lam updated the fuel prices for the other types of generation to September 1992 fuel prices. Heavy oil and natural gas prices were not updated because there was none or very little generation using these two fuels in September. Witness Lam recommended updated fuel prices as follows: (1) coal price of $14.26/mWh; (2) nuclear price of $4.59/mWh; (3) internal combustion turbine of $21.33/mWh; and (4) other purchased and interchanged power price of $15.12/mWh.

Witness Ross and witness Evans, on rebuttal, accepted all of the fuel prices recommended by witness Lam. In the absence of any evidence to the contrary, the Commission concludes that the Company fuel prices accepted by the Public Staff and fuel prices recommended by the Public Staff and accepted by the Company are reasonable and appropriate for use in this proceeding.

Accordingly, the fuel calculation incorporating these conclusions is shown in the following table:

	Adjusted Generation (mWh)	Fuel Price $/mWh	Fuel Dollars (000's)
Coal	28,130,404	14.26	$401,140
Nuclear	20,474,196	4.59	93,977
Heavy Oil	2,070,346	24.90	51,552
Natural Gas	95,061	30.59	2,908
Internal Combustion	1,530,090	21.33	32,637
Hydro	2,302,348		
Pumped Storage	(2,192,202)		
Purchase & Interchange			
NUG	6,784,633		
Other	5,665,469	15.12	85,662
Interruptible Sales	(2,551,212)		(28,446)
System mWh Sales & Total Fuel Cost	58,613,478		$639,430
Base Fuel Factor			1.091¢/kWh

The Commission concludes that adjusted fuel test period expenses of $639,430,000 and the base fuel factor of 1.091¢/kWh, excluding gross receipts tax (1.127¢/kWh with gross receipts tax), is reasonable and appropriate for use in this proceeding. No party opposed this calculation. This approved base fuel factor is 0.078¢/kWh lower than the current level in effect of 1.205¢/kWh, including gross receipts tax (this consists of the current base fuel factor of 1.204¢/kWh and the current fuel adjustment increment from the fuel adjustment proceeding in Docket No. E-22, Sub 329, of 0.001¢/kWh, all including gross receipts tax). Such change will result in a decrease in fuel revenues of $2,076,777 based upon the adjusted level of sales of 2,662,535 mWh for the test year through the update period ending September 30, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 110-112

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

North Carolina General Statute 62-133.2(d) requires the Commission to "incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case." Further, Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Company witness Evans testified that the Company overcollected its fuel expense by $1,308,510 during the test year ending June 30, 1992. He calculated interest for this overcollection of $218,085 in accordance with Rule R8-55(c)(5) using a Commission approved 10% interest rate. Further, witness Evans testified that the adjusted North Carolina jurisdictional fuel clause test year sales are 2,629,412 mWh. Public Staff witness Lam testified that he reviewed the Company's calculations of the fuel expense overcollection, the interest for this overcollection, and the North Carolina jurisdictional sales and agreed with the results.

The Company is proposing to refund the fuel revenue overcollection and associated interest to the customers over a 12-month period beginning March 1, 1993, using the adjusted North Carolina retail sales of 2,629,412 mWh as determined by the Company and accepted by the Public Staff.

The Commission concludes that the Company's calculation of the fuel revenue overcollection and associated

interest of $1,308,510 and $218,085, respectively, are appropriate for use in this proceeding and should be refunded to the customers over a 12-month period. No party opposed these calculations. This refund should be in the form of a separate EMF rider.

The $1,308,510 overcollected fuel revenue plus the $218,085 of interest was divided by the adjusted North Carolina jurisdictional sales of 2,629,412 mWh to arrive at the Company's proposed EMF decrement of 0.058¢/kWh, excluding gross receipts tax (0.060¢/kWh including gross receipts tax). Public Staff witness Lam accepted this proposed EMF decrement. The Commission concludes that there being no controversy, the proposed EMF decrement of 0.058¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding, and shall become effective on the date of this Order and shall expire one year from that date.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 113

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Lam.

Based upon our prior findings in this proceeding the Commission finds that the final fuel factor approved for usage in this case is 1.033¢/kWh. This final fuel factor consists of a base fuel factor of 1.019¢/kWh and an EMF decrement rider, including interest, of 0.058¢/kWh, all excluding gross receipts tax.

IT IS, THEREFORE, ORDERED as follows:

1. That NC Power is authorized to adjust its electric rates and charges effective for service rendered on and after the date of this Order to produce an increase in gross annual revenue, excluding fuel revenue, from its North Carolina retail operations of $10,642,000 based upon the adjusted test year level of operations.

2. That the Company shall replace the current base fuel factor of 1.204¢/kWh, including gross receipts tax, approved in general rate case Docket No. E-22, Sub 314, with the new base fuel factor of 1.127¢/kWh, including gross receipts tax, approved in this proceeding. The Company shall also refund over-recovered fuel expense and interest in the form of a separate rider (an EMF decrement of 0.060¢/kWh including gross receipts tax). This rider shall become effective on the date of this Order and shall expire one year from that date.

3. That the Company is authorized to place in effect an increment rider of 0.066328¢/kWh to recover the remaining unamortized balance of the North Anna Unit 3 abandonment loss. This rider shall become effective on the date of this Order and shall expire one year from that date.

4. That within five (5) working days after the date of this Order, the Company shall file with the Commission five copies of its rate schedules and service regulations designed to produce the increase in revenues adopted herein in accordance with the rate design guidelines attached hereto as Appendix A. The rate schedules required herein shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule.

5. That the Company shall prepare cost allocation studies for presentation with its next general rate case which allocate production plant based on the following methodologies: (a) Summer/Winter Peak and Average; (b) Summer/Winter Coincident Peak; (c) Average and Excess. The studies shall be included in Item 45 of Form E-1 of the minimum filing requirements for general rate applications.

6. That within 10 working days after the date of this Order, the Company shall file with the Commission 30 copies of computations showing the overall North Carolina retail rate of return and the rates of return for each

rate schedule which will be produced by the revenues approved by this Order. These computations shall be based on the cost allocation methodology approved by this Order.

7. That the Company shall give appropriate notice of the approved rate increase by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle following the filing and approval of the rate schedules described herein. The Company shall submit its proposed customer notice to the Commission for approval before it is mailed to the customers.

8. That the Company shall file new revised standards necessary to qualify for the Residential Conservation Reduction (RCR), which shall show that the relative benefit of the new revised standards to the new building code is substantially the same as the relative benefit of the current standards to the current building code as described herein. The new revised standards shall be filed with the Commission by April 15, 1993.

9. That the proposed new Line Extension Plan as described herein is hereby approved to become effective 90 days after the date of this Order.

10. That the Company shall make a study of the fuel costs and other costs incurred to serve the LGS customer class relative to the remainder of the system in accordance with the Commission's conclusions described herein. The results of the study and supporting workpapers shall be filed with the Commission and the Public Staff within 12 months after the date of this Order. The Company shall also file quarterly reports with the Commission regarding the progress of the studies as described herein.

11. That the company shall file a report with the Commission approximately 12 months after the date of this Order describing the number of customers added and lost from the curtailable rate schedules 6C, SG and CS since the date of this Order.

12. That the Company's proposed change to paragraph II. A.1 of its Terms and Conditions for the delivery of electric service rules and regulations is disapproved.

13. That the other proposed rate designs and modification and the other proposed changes in the Terms and Conditions are approved and may be implemented.

14. That the Public Staff shall investigate Vepco's NUG contracts for projects in commercial operation in conjunction with NC Power's next general rate case and present the results of such investigation as part of its testimony in that proceeding.

ISSUED BY ORDER OF THE COMMISSION

This the 26th day of February, 1993.

NORTH CAROLINA UTILITIES COMMISSION

/s/ Geneva S. Thigpen
GENEVA S. THIGPEN
Chief Clerk

[SEAL]

Commissioner Cobb dissenting in part.

APPENDIX A

NORTH CAROLINA POWER

DOCKET NO. E-22, SUB 333

Guidelines for Design of Rate Schedules

(A) Set the Basic Customer Charge for Residential Service at $9.50.

(B) Hold the extra charges and miscellaneous service charges at the same levels proposed by the Company.

(C) Distribute the overall revenue increase approved herein in accordance with the following rate of increase indices:

	Rate of Increase Index
Residential	1.125
Small General Service	1.000
Large General Service	0.875
Outdoor Lighting	1.000
Traffic Signals	1.000
Overall	1.000

(D) Maintain revenue neutrality between comparable time-of-use rate schedules and non-time-of-use rate schedules.

(E) Maintain the relative price levels proposed for each rate schedule consistent with the overall rates of increase approved herein, except as specifically revised herein.

DOCKET NO. E-22, SUBS 333 AND 335

COMMISSIONER COBB, DISSENTING, IN PART.

1. I dissent from Finding of Fact 59 which reduces the operation and maintenance expense by $1,390,000 to reflect alleged unreasonable purchase capacity costs in connection with the Hadson projects. While I agree that this Commission is not bound by the actions of the Virginia State Corporation Commission as a matter of law, I do not feel that the factual situation in this case justifies such disallowance. Neither do I agree with the majority concerning the standards to be met for disallowance.

The majority cites other cases involving the adjustment of fuel expenses to reflect abnormal weather conditions and other factors as justification for its conclusion that there need not be a finding of management imprudence to disallow expenses. These decisions are readily distinguishable in that failure to adjust clearly would have resulted in the substantial over recovery of expenses whereas the majority decision in this case will preclude the recovery of $1,390,000 in costs actually incurred.

In my opinion, North Carolina Power did everything a reasonable and prudent person would be expected to do but became subject to pay these purchased power costs because of the decision of an authority having jurisdiction of the subject matter. I would hold that to disallow the recovery of costs actually incurred, we would need to find a lack of reasonable and prudent action on the part of North Carolina Power.

2. I also dissent from those parts of Findings of Fact 60, 61 and 62 to the extent that they conflict with Commission Rules R12-12 and A12-13. Once again the majority has solved a difficult problem by "splitting the difference" and disallowing half of the alleged competitive advertising because some of the ads made reference to natural gas. While compromise verdicts may be excused where reached by juries, it is my understanding that our

findings of fact must be based upon evidence in the record. They also must be in conformance with our rules.

As I read Rules R12-12(d) and R12-13(c), advertising which comes within any of the six subparagraphs of R12-12(d) will be deemed reasonable operating expenses except to the extent that the expenditures might have exceeded a reasonable amount. There is no reference in either of these rules to competitive advertising. In my opinion, the thrust of the entire co-op advertising company was to promote energy efficiency so that the entire expense would be reasonable under Rule 12-12(d)(1) and (5). If we are going to disallow such advertising because of the Public Staff's contention that ads should not promote the use of electricity over gas, we should amend our rules to specifically disallow such advertising.

The disallowance of the "promotional advertising" by the majority clearly is inconsistent with the definition of such advertising in Rule R12-12(c). The rule defines such advertising as that which encourages the use of electricity where ". . . such appliance, equipment, or service would promote or encourage indiscriminate and wasteful consumption of energy. . . ." Furthermore, such advertising must have a disclaimer to the extent that the advertising is not paid for by the customers of the utility. I would have found this advertising to be recoverable either under Rule R12-12(d) or Rule R12-13(d).

I also have difficulty with the disallowance of the "image advertising" because recovery for such expenses is not precluded by our rules. If such a policy is to be continued, the rules should be amended. Until this is done, I am of the opinion that these expenses should have been recovered under Rules R12-12(d) and R12-13(d).

3. Finally, I dissent from Finding of Fact 63 which disallows half of the compensation of officers. My opinion in this regard is set forth in my dissent in Docket No. E-22, Sub 314 and need not be repeated here. Suf-

fice to say I continue to believe that such disallowance is arbitrary and capricious and beyond the authority granted by law.

/s/ Laurence A. Cobb
LAURENCE A. COBB

APPENDIX D

Order of the Federal Energy Regulatory Commission (February 28, 1990)

FEDERAL ENERGY REGULATORY COMMISSION

Docket No. ER90-80-000

DOSWELL LIMITED PARTNERSHIP

ORDER ACCEPTING RATES FOR FILING, NOTING INTERVENTIONS, AND GRANTING AND DENYING WAIVERS

(Issued February 28, 1990)

Before Commissioners: Martin L. Allday, Chairman; Charles A. Trabandt, Elizabeth Anne Moler and Jerry J. Langdon.

Background

In December 1986, Virginia Electric and Power Company (Virginia Power) solicited proposals from developers of qualifying facilities (QFs) for 700 MW of intermediate and peaking capacity for availability in the

winter of 1990. The solicitation specified energy and capacity charges reflecting the projected costs of Virginia Power's gas-fired combined cycle unit, Chesterfield 7. In response to the solicitation, 27 parties responded with proposals for more than 5000 MW of capacity. Virginia Power executed seven contracts with a total capacity of 1200 MW.

One of the offers accepted by Virginia Power was from Intercontinental Energy Corporation (Intercontinental). Intercontinental offered to construct two 300 MW gas-fired combined cycle units, and Virginia Power executed an agreement for each unit with Intercontinental in 1987.

On June 21, 1989, Intercontinental assigned the agreements to Doswell Limited Partnership (Doswell). Doswell is a limited partnership consisting of one general partner and one limited partner (Doswell I, Inc. and Doswell II, Inc., respectively), which are both wholly owned subsidiaries of Diamond Energy. Diamond Energy is a wholly owned subsidiary of Mitsubishi Corporation.[1]

On November 22, 1989, as supplemented on December 28, 1989, Doswell submitted the two agreements with Virginia Power for filing with the Commission as initial rates.[2] Although Intercontinental initially responded to Virginia Power's proposal as a cogenerator, Doswell is not a cogenerator; rather it is an independent

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[1] Dowell states that other entities may acquire equity interests in the units, but these entities have not been identified. We note that, according to Doswell's application (at p. 12, n. 13), Diamond Energy is engaged in the development of three other electric cogeneration facilities in Texas, California and New York, none of which will sell to Virginia Power.

[2] The rate schedule designations are:

Doswell Limited Partnership, Inc.
Rate Schedule FERC No. 1 - Unit 1
Rate Schedule FERC No. 2 - Unit 2

power producer (IPP). Doswell requests Commission action on the rate filings no later than March 1, 1990, in order to obtain financing in sufficient time to meet the construction deadlines which are established in the agreements.[3] Doswell also requests waiver of various Commission accounting and reporting requirements.

Provisions of the Agreements

Under the agreements, service is expected to commence in 1991 and continue for 25 years, with possible five-year extensions. There are no minimum take requirements and Virginia Power would schedule energy only when it is economical to do so. The rates for service are intended to track Virginia Power's costs for Chesterfield 7, a gas-fired combined cycle facility which is currently under construction in Virginia.[4] The agreements also specify liquidated damages to be paid to Virginia Power if the units are not in service by December 1, 1991, do not achieve the specified dependable capacity upon installation, or do not maintain at least 85 percent of the specified dependable capacity thereafter.

Doswell cites the cost of Chesterfield 7 as an avoided cost rate for the units because Virginia Power used the projected cost of Chesterfield 7 to design the rates it specified in its solicitation. Moreover, in 1988, the Virginia State Corporation Commission (Virginia Commission) determined that Chesterfield 7 reflected Virginia Power's avoided costs for purposes of setting certain QF

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[3] On February 7, 1990, Doswell filed a petition for expedited treatment, requesting that the Commission consider the filing at its meeting of February 14, 1990.

[4] The capacity charges would be $10.2567/kW/month for the first 15 years and $5.8933/kW/month thereafter. Payments would be suspended or reduced under various circumstances if the units do not perform as expected. There would also be various other rate components to compensate Doswell for its fuel costs, as well as fuel storage and transportation costs.

contract rates. Doswell argues that its rates should be compared with Virginia Power's avoided costs at the time of the 1987 agreements.

In 1989, Virginia Power revised its gas supply arrangements for Chesterfield 7 and provided Doswell and other gas-fired projects the opportunity to modify their agreements to conform to this revision. Doswell submitted the revised power purchase agreements to the Commission on January 5, 1990. Doswell also submitted on January 16, 1990, an affidavit from Virginia Power certifying that the rates do not exceed Virginia Power's avoided costs.

In support of its argument that the proposed rates are just and reasonable, Doswell states that it lacks, and its predecessor Intercontinental lacked, market power over Virginia Power, and that the rates reflect Virginia Power's avoided costs. In this regard, Doswell states that: (1) Virginia Power can and does build new capacity as necessary; (2) neither Doswell nor Intercontinental could limit Virginia Power's access to other suppliers because (a) Doswell does not, and Intercontinental did not, own or control any transmission facilities except to interconnect its generation facilities with purchasing utilities' systems, and (b) Doswell does not, and Intercontinental did not, own or control any franchised service area or otherwise sell electricity to Virginia Power or to an adjacent utility; and (3) Virginia Power has and will continue to have numerous supply options available, including self-generation. Moreover, Doswell notes that the 600 MW of capacity in this proposal is only four percent of Virginia Power's projected system capacity for 1991.

Doswell cites several safeguards in the 1987 agreements that it believes will ensure that the facilities will be constructed and operated reliably by Doswell. These include requirements for various progress and operating reports, operational covenants, a security deposit, per-

formance testing, a default provision, and an insurance requirement.

Notice of the original and supplemental filings were published in the *Federal Register*,[5] with comments, protests or intervention due on or before December 27, 1989, and January 19 and 23, 1990, respectively. On December 19, 1989, Virginia Power filed a motion to intervene that supports acceptance of Doswell's filing but raises no substantive issues. On December 27, 1989, Tellus, Inc. filed a motion to intervene that raises no substantive issues.

On February 13, 1990, the Virginia Commission issued its Opinion and Final Order in Case No. PUE890068, granting Doswell a certificate of public convenience and necessity for the units. The Virginia Commission noted that: (1) Virginia Power has a need for capacity in the early 1990's; (2) the loss of capacity associated with the Doswell project would leave Virginia Power with a minimal allowance for further attrition of purchased power; (3) the Doswell project is optimally located near a Virginia Power transmission line and the Richmond-Washington corridor; (4) its staff reported that Doswell's rates, based on the avoided costs of Chesterfield 7, are reasonable when compared to payments for power from similar projects; (5) there is no reason to believe that the costs of the project will become unreasonable because the project is no longer a cogeneration facility; and (6) Doswell appears to have the technical ability and financial viability to undertake the project. The Virginia Commission required, as a condition to its approval, that Doswell: file with the state commission copies of its revised, executed power contract and operating contract with Virginia Power; comply with any and all reporting requirements directed by the state com-

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[5] 54 Fed. Reg. 50,429 (1989), 55 Fed. Reg. 1258 (1990), and 55 Fed. Reg. 1865 (1990), respectively.

mission related to construction, operation and technical aspects of the project; not sell or transfer any of its utility assets or the certificate of public convenience and necessity without first seeking the state commission's approval; and file certain described information, reports and contracts with the Clerk of the Virginia Commission. The Virginia Commission's order also provided that the certificate holder and all general partners of any partnership holding any interest in the certificate, their successors and assigns are subject to all of the regulatory provisions of Title 56 of the Virginia Code which are not preempted by federal law.

Discussion

Under Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (1989)), the timely, unopposed motions to intervene of Virginia Power and Tellus, Inc. serve to make them parties to this proceeding.

Pricing Flexibility

To approve Doswell's proposed market-oriented rates, the Commission must determine that the rates are just and reasonable under section 205 of the Federal Power Act. To determine that the proposed rates are just and reasonable, the Commission must find that they fall within a "zone of reasonableness," where the rates are lower than what would be excessive to consumers and higher than what would be confiscatory to investors.[6] The Commission has allowed pricing flexibility in recent cases, and has concluded that noncost based rates fall within a zone of reasonableness in circumstances where the seller can show that it lacks market power or has mitigated its

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[6] *See Jersey Central Power & Light Company v. FERC*, 810 F.2d 1168, 1177 (D.C. Cir. 1987).

market power, and there is a pricing cap based either on the seller's costs,[7] or on the purchaser's avoided cost.[8]

In substance, Doswell's rates initially were established in a QF solicitation in which Doswell's predecessor, Intercontinental, participated.[9] However, we cannot accept a QF avoided cost rate as just and reasonable for a non-QF under the Federal Power Act without examining whether market forces were at work to establish the price and nonprice terms agreed to by the parties. Doswell claims that it and its predecessor lack market power over the purchaser, Virginia Power, and has provided a certification from Virginia Power that its rates do not exceed Virginia Power's avoided costs. Based on the information provided in this filing, we find sufficient assurances that the rates fall within a zone of reasonableness.

The agreements between Doswell and Virginia Power arose out of a 1986 solicitation by Virginia Power to many QF developers. According to the solicitation letter, the quantity of electric capacity that was then being proposed by cogenerators and small power producers was significantly greater than the amount of capacity the company needed. As a result, the company told developers that it was withdrawing current offers, rejecting previously

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[7] *Pacific Gas and Electric Co. (Turlock)*, 42 FERC ¶ 61,406 (1988), *order on rehearing*, 43 FERC ¶ 61,403 (1988); *Pacific Gas and Electric Co. (Modesto)*, 44 FERC ¶ 61,010 (1988), *order on rehearing*, 45 FERC ¶ 61,061 (1988).

[8] *Citizens Power & Light Corporation (Citizens Power)*, 48 FERC ¶ 61,210 (1989); *Ocean State Power (Ocean State)*, 44 FERC ¶ 61,261 (1988); *Orange & Rockland Uitlities*, 42 FERC ¶ 61,012 (1988); *Baltimore Gas & Electric Co.*, 40 FERC ¶ 61,170 (1987).

[9] We note that under its January 3, 1990 agreement with Virginia Power, Doswell reserved the right to obtain QF status anytime in the future without any impact on the purchase prices in the agreement.

received offers, and requesting new proposals from QF developers wishing to contract with it.

The solicitation letter stated that the capacity and energy payments would be based on the estimated costs of the company's planned Chesterfield 7 unit and that full dispatchability would be a prime selection factor. Twenty-seven QF developers responded to the solicitation with offers that resulted in a total offered capacity approximately seven times greater than the amount requested. Virginia Power entered into negotiations with the developers of the competing projects.[10] Upon concluding its negotiations with the competing QF suppliers, Virginia Power selected the seven projects that it believed offered the best packages of terms. Intercontinental, Doswell's predecessor, was one of those seven.

This transaction was clearly the product of a market process. Several factors lead us to this conclusion. First, the buyer, Virginia Power, had discretion over the price and other terms in the deal. This is best evidenced by the fact that its original solicitations, which produced a greater than anticipated supply response, were withdrawn and reoffered in a manner that allowed Virginia Power greater discretion in selecting the winning bids.

Second, the seller, Intercontinental, also had discretion in the transaction. The fact that Virginia Power offered a "take it or leave it" price in no way constrained potential sellers from offering a lower price to improve their prospects for being chosen in the solicitation.

Third, the parties negotiated nonprice factors. Virginia Power's negotiations with the developers focused on what are often referred to as nonprice terms and conditions (*e.g.*, degree of dispatchability, security deposits, performance dates, and penalties for nonperformance). The "non-price" characterization is something of a misnomer because clearly such provisions can have a direct and

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[10] *See* Petition, Appendix A, Tab 9.

significant impact on the lifetime cost of a project to the buyer.[11] Virginia Power's purpose in pursuing the negotiations with each competing supplier was to obtain a package of the price and other terms that would minimize the total effective cost of that supply option.

All of these factors taken together make it clear that the rate, terms and conditions of this transaction were the product of a multiparty, market-oriented process. Having concluded that there was a market at work, it is next necessary to determine whether Intercontinental or Doswell had market power in this market.[12]

There are several factors that lead us to conclude that both Intercontinental and its successor, Doswell, lacked market power over Virginia Power. First, Intercontinental did not own or control, and was not affiliated with any entity that owned or controlled, transmission facilities within or around the Virginia Power service area, other than those necessary to interconnect with Virginia Power for this sale. Therefore, Intercontinental was not in a position to prevent Virginia Power from reaching competing suppliers. At the time of the assignment of the agreements by Intercontinental to Doswell, the above facts were also true for Doswell.

Second, there is no evidence that Intercontinental or Doswell was a dominant firm in any generating market that might be relevant to providing capacity and energy to Virginia Power. Intercontinental and Doswell were

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[11] An example may clarify this point. If a project is not completed on schedule, Virginia Power may have to incur the cost of purchasing replacement power to make up for the shortfall in capacity. A contract provision that assesses penalties on the project developer for missing deadlines would mitigate these costs.

[12] Market power for a seller exists when the seller can significantly influence the price in the market by withholding service and excluding competitors for a significant period of time. 48 FERC at p. 61,777. It also exists for a seller that can hold price constant and offer an inferior service while excluding competitors.

new entrants into Virginia Power's market. Neither owns or owned other generating resources in Virginia Power's service area or in any adjacent service area.

Typically, a seller with market power can withhold capacity to raise price in the market. If Intercontinental or Doswell had attempted to withhold service (either by not responding to the Virginia Power's solicitation or by threatening not to sign a contract unless certain demands were met), Virginia Power could have selected one or more of the other respondents at the same price or constructed the capacity itself.

Third, there is no evidence that either Intercontinental or Doswell controlled resources that allowed it to erect any other barrier to potential competing generation suppliers. For example, they did not have sole rights to the last or one of the last viable sites in nor near Virginia for new generation capacity.[13]

In light of these factors, we conclude that neither Doswell nor Intercontinental could have significantly influenced the price Virginia Power paid for new capacity and energy.

We also conclude that there is no evidence of self-dealing [14] because Doswell is not affiliated or involved in any joint venture with its purchaser Virginia Power, nor is it affiliated or involved in a joint venture with the franchised utility in the purchaser's service area (in this case, both the franchised utility and the purchaser are the same entity). However, to ensure that there is no oppor-

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[13] This is shown by the fact that, in 1988, after it had signed the contract with Intercontinental, Virginia Power negotiated 19 more contracts for a total of 2000 MW of capacity to be constructed at various sites accessible to Virginia Power. *See* Petition at 15.

[14] A problem with self-dealing occurs when an entity sells to or buys from an affiliate on terms that are more favorable than would be available to other market participants.

tunity for self-dealing or other abuses in the future,[15] we will require Doswell to report to the Commission any future affiliate or joint venture dealings with Virginia Power.[16]

In addition to providing support for the conclusion that Doswell has not exercised market power over Virginia Power, Doswell has provided a statement from Virginia Power that Doswell's rates do not exceed Virginia Power's avoided cost. The 1986 solicitation indicated that payments would reflect avoided cost and that avoided cost would be based on Virginia Power's Chesterfield 7 unit. That Chesterfield 7 was an accurate representation of Virginia Power's avoided cost is corroborated by the Virginia Commission's adoption of Chesterfield 7's costs to set avoided cost rates for certain QF contracts in the same time frame involved here.[17] Although Doswell is

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[15] We note Article 13.6 of the January 3, 1990 agreement between Doswell and Virginia Power gives the utility the right of first refusal to acquire the seller's general partnership equity or assets.

[16] As discussed below, *infra* p. 10, we are also requiring Doswell to report to as any disposition of shares in the partnership to an electric utility or its affiliate. If Doswell engages in these activities, or affiliate or joint venture dealings with Virginia Power, reexamination of Doswell's rates may be appropriate.

[17] In 1988, the Virginia Commission ratified and adopted a final order of an arbitrator which found that avoided cost pricing for four QF projects should be based on Virginia Power's cost of constructing and operating Chesterfield 7 as of November 12, 1987, which was the date the arbitration petitions were filed. *See Petition of Ultra Cogen System, Inc., et al.*, Case No. PUE870088 *et al.*, Award and Final Order of Thomas P. Harwood, Arbitrator, September 30, 1988 and Order Ending Proceeding, November 18, 1988. *See also* Memorandum dated April 27, 1988 from Thomas P. Harwood, Jr. to James C. Roberts, Esq., *et al.* We also note that the Virginia Commission granted a certificate of public convenience and necessity for Chesterfield 7 on July 17, 1987, as amended on September 28, 1988. Doswell Petition filed November 22, 1989, notes 15 and 19. Chesterfield 7 is scheduled to go into service in June 1990.

an IPP rather than a QF, Virginia Power's avoided costs are the same whether the seller is an investor-owned utility, QF, IPP or other marketer. The fact that the price paid to Doswell could not exceed Virginia Power's avoided cost assures us that the rate does not exceed the upper end of the zone of reasonableness.[18]

In sum, we believe that the rates are just and reasonable because there is no evidence that either Intercontinental or its successor Doswell has exercised market power or engaged in self-dealing, and because the rates will not exceed Virginia Power's avoided cost during the same time frame that the Doswell contracts were executed.

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[18] The issue of whether Doswell is a reliable and least cost alternative goes to Virginia Power's prudence in making this purchase, which is an issue that need not and should not be resolved in this docket. Our finding that Doswell's rate is "just and reasonable" in this filing does not preclude this Commission or the Virginia Commission from examining the prudence of Virginia Power's purchase in a subsequent rate case. The Commission reaffirms its conclusion that the Supreme Court's decisions in *Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953 (1986), or subsequent cases, do not preclude state regulators from reviewing the prudence of a utility's purchasing decisions. While *Nantahala* held that "a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable," 476 U.S. at 966, the Court did not decide the issue whether a state agency can inquire into a utility's prudence in choosing to pay the FERC-approved wholesale rate of another supplier. *See also Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Comm'n*, 837 F.2d 600 (3rd Cir.), *cert. denied*, 109 S.Ct. 365 (1988); *Pike County Light and Power Co. v. Pennsylvania Public Utility Comm'n*, 465 A.2d 735, 737-738 (1983). In addition, our finding here does not preclude the Virginia Commission from examining, as it has done here, the "viability and appropriateness of the Doswell project" in a certificate of public convenience and necessity proceeding (Virginia Commission Opinion and Final Order, Case No. PUE890068, p. 6).

Waivers

Because Doswell's rates are not cost-based, they are not susceptible to certain cost data requirements. Therefore, we will grant Doswell's request to waive the filing requirements under section 35.12(b) for initial rate schedules.

We will deny Doswell's request to waive the requirements in Part 33 of our regulations (regarding dispositions, mergers and consolidations of facilities, and acquisitions of securities of a public utility) without prejudice to Doswell's refiling the waiver request at the time that Doswell may engage in such a transaction. In addition, we will require Doswell to report to us any disposition of shares in the partnership to an electric utility or its affiliate. This requirement will allow the Commission to monitor any affiliations that may involve instances of self-dealing or other abuses.

Doswell also requests waiver of Parts 41, 101, and 141 of our regulations (regarding accounting and reporting requirements); Part 50 (regarding procurement policy and practices); an abbreviated filing under Parts 45 and 46 (prescribing filing requirements for interlocking directorates); and blanket approval under Part 34 of all future issuances of securities and assumptions of liability by Doswell.

We will grant these waivers to the same extent as we did in *Citizens Power*. *Doswell* describes itself as a special purpose, one-asset entity that has not developed and does not presently own any other energy propects or facilities. The only transmission facilities that Doswell owns or controls are those used to interconnect its generating facilities to its purchaser, Virginia Power. Based on its limited holdings and purpose, we believe that these requirements may be unnecessarily burdensome.

Finally, we will grant Doswell's request to waive the advance notice requirements in section 35.3 of our regulations, given the expressed financing and construction

contingencies. The rate schedules shall become effective as of the date of this order.

The Commission orders:

(A) Doswell's initial rates are hereby accepted for filing to be effective as of the date of this order.

(B) Doswell shall report to the Commission any future affiliate or joint venture dealings with the Virginia Power.

(C) Doswell's request for waiver of Part 33 of the Commission's regulations is hereby denied without prejudice, as provided in the body of this order. Doswell shall report to the Commission any disposition of shares in the partnership to an electric utility or its affiliate.

(D) Doswell's request for waiver of section 35.12, and Parts 41, 50, 101, and 141 of the Commission's regulations is hereby granted.

(E) Within thirty (30) days of the date of this order, any person desiring to be heard or to protest the Commission's blanket approval of issuances of securities or assumptions of liability by Doswell should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214).

(F) Absent a request for hearing within the period set forth in Ordering Paragraph (E) above, Doswell is authorized to issue securities and assume obligations or liabilities as guarantor, endorser, surety, or otherwise in respect of any security of another person; provided that such issue or assumption is for some lawful object within the corporate purposes of the applicant, and compatible with the public interest, and is reasonably necessary or appropriate for such purposes.

(G) The Commission reserves the right to require a further showing that neither public nor private interests will be adversely affected by continued Commission approval of Doswell's issuances of securities or assumption of liability.

(H) Until further order of this Commission, any person now holding or who may hold an otherwise proscribed interlock involving Doswell is authorized to hold such position provided that such person files the application required by Ordering Paragraph (I) below.

(I) Until further order of this Commission, the full requirements of Parts 45 and 46 of the Commission's regulations, except as noted below, are hereby waived with respect to those persons subject to Ordering Paragraph (H) above, and those persons instead shall file a sworn application providing the following information:

(1) full name and business address; and

(2) all jurisdictional interlocks, identifying the affected companies and the positions held by that person.

(J) The Commission reserves the right to require a further showing that neither public nor private interests will be adversely affected by the continued holding of the interlocks addressed above.

(K) Doswell's request for waiver of section 35.3 of the Commission's regulations is hereby granted.

Commissioner Trabandt *concurred* with a separate statement attached.

Charles A. TRABANDT, Commissioner, *concurring*:

I agree that the Commission should approve the arrangement under which Doswell Limited Partnership (Doswell) will sell electricity to Virginia Electric and Power Company (VEPCO), although I would add to the conditions the order contains. In addition, while I find

the rate just and reasonable under the Federal Power Act, I do so for different reasons from those the order offers, *see particularly,* slip op. at 6-7. I explain below that I cannot embrace as readily as the majority the notion that the sale price, which VEPCO announced in advance it would pay, resulted from the push and pull of a market.

Nevertheless, other facts in the record lead me to support the outcome of this order. I also note that the novelty of electric power procedures at the time VEPCO sought suppliers argues in favor of approving the resulting contract. Considering the state of sophistication on these matters in those days, the parties have done their best and enough to satisfy the Federal Power Act. Because the difference in rationale involves more than a quibble over legal niceties, I write to explain my position.

1. Why the Market Rationale Squeezes the Contours of the Just and Reasonable Standard

In my concurring opinion in *Citizens Power & Light Co.,* 48 FERC ¶ 61,210, at pp. 61,782-61,786 (1989) and my dissent in *Ocean State Power,* 44 FERC ¶ 61,261, at pp. 61,988-61,993 (1988), I wrote at length on how the Commission may legally approve as just and reasonable under the Federal Power Act rates that the Commission would reject as too high under traditional individual cost regulation. I specifically refer the reader there for the full discussion.

For purposes of this opinion, keeping in mind the D.C. Circuit case law—(1) the rate must emerge from negotiations in a truly competitive market; (2) the Commission must establish a rate ceiling; and (3) the order approving the rate must contain a mechanism to monitor the situation—suffices. In addition, the Supreme Court in *In re Permian Basin Area Rate Cases,* 390 U.S. 747, 775-777 (1968) (involving the Natural Gas Act's identical just and reasonable standard), held that where the Com-

mission can show individual cost calculations infeasible, the agency may draw from a larger sample of sellers, such as an area or the Nation. Therefore, the Commission may extrapolate individual rates from such composite figures, in place of the costs of the particular regulated company.

The order holds that the Doswell-VEPCO contract meets the criteria the Court of Appeals established. The discussion acknowledges, slip op. at 5, that "Doswell's rates initially were established in a [Public Utility Regulatory Policies Act (PURPA)] solicitation in which Doswell's predecessor . . . participated." That statute allows (and our regulation requires) utilities to purchase electricity from qualifying facilities (commercial sellers of steam or users of renewable energy, collectively, called QFs) at the purchaser's "avoided cost," the price the buyer would have paid for a substitute source—in this case, building a plant itself.

Because Congress established that rate as the maximum for qualifying facilities, whether or not that would pass under the just and reasonable test has no relevance. However, Doswell, which began as a QF, literally lost its steam host (the intended consumer of the steam a QF produces in the cogeneration process), and comes to us as a no-frills generating plant. Therefore, the order, *id.*, correctly states, "we cannot accept a[n] avoided cost rate as just and reasonable . . . under the Federal Power Act without examining whether market forces were at work *to establish the price* and non-price terms. . . ." (Emphasis added.)

In addition, the order points out that the original solicitation that drew Doswell's predecessor to VEPCO contained a fixed price, (i.e., the avoided cost maximum PURPA rate) set in advance. VEPCO stated it would pay suppliers a rate equal to the cost of the most recent plant the utility had sought approval to build. Therefore, VEPCO's avoided cost here represents the highest

price any buyer would pay. No rational company would pay someone else more than what the buyer would have to expend to build for itself. As "what the market will bear," that amounts to an unjust and unreasonable rate.

I would note at this point that the courts have recognized, even in affirming the Commission's desision to require rates for QFs to equal avoided cost (unless the parties negotiate a lower figure), that PURPA represents a special case, the exception to the "just and reasonable" rule. When the D.C. Circuit originally considered the Commission's PURPA rate regulations, the court reversed.

The panel held that because PURPA mandates that QF rates also be "just and reasonable to the electric consumers of the electric utility," and "in the public interest," the law required the Commission to consider a rate level lower than the maximum amount, so that consumers may share the benefits of the QF transaction. The court held that competition among QF's may lead to lower rates. *American Electric Power Corporation v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd sub nom. American Paper Institute v. American Electric Power Corporation*, 461 U.S. 402 (1983). The Supreme Court rested its reversal of the Court of Appeals on the argument that the Commission properly gave content to congressional intent to encourage PURPA projects. The Court did not hold avoided cost just and reasonable. Therefore, I am satisfied, as the order concludes, slip op. at 5, that, an avoided cost rate from a seller not a QF, does not inherently qualify as just and reasonable.

Nevertheless, the order approves Doswell's avoided cost rate. The majority, slip op. at 6, finds a market "process" established the price, thus, on the surface, providing further analysis. However, the analysis consists of the following reasons: (1) VEPCO *could have asked* for a different price; (2) Doswell *could have offered* another price; and (3) the two negotiated *nonprice* "factors." I respond: (1) VEPCO did not; (2) Doswell (or any

buyer guaranteed a price) would not; and (3) while non-price terms may "affect the lifetime cost of [the] project," (*id.*), the parties did not negotiate the price itself. In effect, Doswell('s predecessor) began as a QF and kept its PURPA rate when it turned into a conventional generating plant. The order notes, slip op. at n.9, that Doswell may again become a QF (I presume if it finds a purchaser for its steam), entitled to an avoided cost rate.

As far as its Federal Power Act analysis, the order starts out with the proper intention but misses in the execution. Here lies my concern. The majority today approved the Doswell-VEPCO contract as the product of price negotiations. The Commission will have to strain the next time to reject a filing that contains an avoided cost term for a seller: (a) owning a plant (unlike *Citizens* which only took title to electricity) but; (b) not affiliated with the purchasing utility; and (c) having no market power over it. In short, what the majority tailored today provides a perfect fit for an independent power producer (IPP) obtaining preferred rate treatment, i.e., perforce an avoided cost rate without undergoing a market process.

Additionally, the court in *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168 (D.C. Cir. 1987), which, this order cites, slip op. at 4-5, requires that the Commission "assure itself . . . that 'each of [a rate] order's essential elements is supported by substantial evidence'. . . ." 810 F.2d at 1177, quoting *Permain*, 390 U.S. at 792. Here, the order creates a market out of mere conjecture for which I find no evidence in the record. Clearly, to establish the market-based competition necessary to support this particular avoided cost rate, the Comission should have facts, data and evidence, not hypothetical possibilities.

I also note, as I have in *Ocean State*, 44 FERC at p. 61,989, that the Notice of Proposed Rulemaking on IPP's proposed avoided cost as one of three possibile

ways to set prices for that type of electricity. As I stated earlier, bidding has advanced since this solicitation occurred, so I assume we will never see a contract with a predetermined price in the future. Nevertheless, the precedent lurks in the Reports for possible misuse later.

Moreover, as I now explain, I think the Commission could have reached its result on a narrower, and safer, basis.

2. The Alternate Route to Approval

The Supreme Court in *Permian* held that the Commission may, under the just and reasonable standard depart from individual cost regulation for gas producers and substitute instead rates that the agency calculated in the aggregate. The Court held, 390 U.S. at 777, that the Commission may make " 'pragmatic adjustments which may be called for by particular circumstances.' " (quoting *FPC v. Natural Gas Pipeline Co. of America,* 315 U.S. 575, 586 (1942)), as long as the statute does not prohibit it. For gas producers, the Court agreed that the Commission could not use individual costs.

In that context the Court held that regulation "may . . . depend upon the contrivance of [different] administrative methods." 390 U.S. at 777. In the case before us, we do not have Doswell's actual costs, for the price its contract with VEPCO calls for—indeed, the entire solicitation—bears no relation to that. Nevertheless, the Virginia Corporation Commission has provided an adequate substitute. That agency reviewed the Doswell-Virginia Power contract in the course of its certificate proceeding, as the order recites in its "Background" section, slip op. at 4.

The state commission found that while the rates are not cost-based as far as Doswell is concerned, the state noted that its staff found them reasonable for this type of project, as a free-standing generator. (State commis-

sion order at 12). In effect, the state's experts allow us to find the rate just and reasonable in the aggregate. While the Federal Power Commission spent years amassing area cost data, neither Doswell nor VEPCO can wait that long and I hold that determination adequate here.

The state commission also rested its decision to issue a certificate on the following findings: that Virginia Power has a need for Doswell's electricity; that Doswell is a viable entity capable of operating a generation facility; that the Virginia staff found the rates reasonable for this type of project; and that Doswell made the necessary arrangements for securing financing and fuel for this project. (State commission order at 12-14). In *Ocean State*, 44 FERC at p. 61,984, we relied on (what I thought invalid or untested) state findings as to the reasonableness of the avoided cost rate. So would I here rely on (what I find proper) state determinations, even though in neither case did the state review the rates for purposes of approving the sales.

A broader principle also is at issue in this case: how much weight or significance should this Commission give to the analysis and conclusions of jurisdictional state commissions as to the reasonableness of the rate (especially if the parties negotiated it) for an IPP's wholesale sales? I would attach significance to any such conclusion, whether it be a conclusion that the rate was reasonable (as here) or unreasonable (as it might be in another future case). The order discusses the Virginia Commission's findings, but only as background information, without expressly identifying it as a specific factor in this Commission's analysis and conclusion.

While the Federal Power Act requires that this Commission ultimately must render a judgment as to the justness and reasonableness of a proposed IPP rate, I am persuaded that we may legally take into account the analysis and conclusions of jurisdictional state commis-

sions, where available. Indeed, I believe that fundamental comity between federal and state authorities in this virgin area of shared responsibility virtually demands that FERC place an appropriate significance and weight on any relevant state commission analysis and conclusion as to the reasonableness of the IPP's rate.

In a similar vein, I am pleased to note that the Commission has expressly declared, slip op. at 9-10, n. 18, that under applicable federal law, the state commission has the authority to approve the prudence of the electric utility's purchases from the IPP. If the future generation sector of the evolving electric utility industry includes a substantial number of IPPs in the generation mix as some experts predict (and many others hope), then it will be imperative that state commissions have the authority to scrutinize the prudence of utility purchasing practices in the selection of power purchase contracts necessary to provide the assured and reliable supply to satisfy the franchise utility's obligation to serve its customers. The Commission's clear and unambiguous declaration here that the Virginia Commission shall have exactly such authority in this first real IPP rate case should go a long way legally to establishing that result.

I would also attach some significance to the fact that VEPCO renegotiated with Doswell in late 1989 the original contract setting the avoided cost rate, which Intercontinental Energy (the original QF project sponsor which VEPCO selected in the QF solicitation but lost its steam host) assigned to Doswell in June 1989. By the time of the renegotiation, which retained the original avoided cost, VEPCO had completed two additional solicitations for power purchases under guidelines the Virginia Commission established in early 1988. The new guidelines included price competition in the bidding process. Thus, as of late 1989, VEPCO (as well as the Virginia Commission) had the benefit of an extensive price competition data bank for purposes of assessing

the reasonableness of the avoided cost rate set for the Doswell project as of January 1990.

Furthermore, the particular avoided cost rate was established based on the projected costs of VEPCO's own Chesterfield 7 unit in 1986 and 1987, but subsequently construction of that unit has been completed. Consequently, VEPCO, the Virginia Commission and this Commission have current and comparable avoided cost-based data on which to assess this rate. Thus, I am satisfied that there are sufficient grounds and substantial evidence to conclude that the Doswell rate is reasonable.

I would also address one final point. I note that the Virginia Commission, at pp. 8-10 of its order, discusses imposing on Doswell the usual state reporting requirements, in light of federal preemption of Doswell's rates to Virginia Power. The Virginia Commisison concluded that "while we have no immediate power to respond to Doswell's security issuances or to its dealings with affiliated interests, we have a vital concern in these subjects because of their potential involvement in future FERC proceedings of interest to th[e state]." Order Issuing Certificate at 8-9.

Even while recognizing that the pre-emption doctrine prevented the state from regulating Doswell's rates, the Virginia Commission required the IPP to file information on "the issuance of stocks and stock certificates or other evidences of interest or ownership, and bonds, notes and other evidences of indebtedness and the creation of liens" on the Doswell property within Virginia (*id.* at 9). The state also required Doswell to report "all contracts or arrangements described in Virginia Code § 56-77 and amendments thereto." *Id.* at 10.

The Virginia Commission concluded that neither the Constitution, the Federal Power Act or the court cases prevented it, in the exercise of its licensing jurisdiction, to impose those reporting requirements. The Virginia

Commission also found, *id.*, that those requirements of themselves will not frustrate federal law. I agree with the Virginia Commission.

These requirements for information help strengthen the monitoring mechanism the courts require, either because the information allows Virginia to file a complaint to open a proceeding or to participate more fully in one someone else initiates. On the understanding that the state will not assume regulatory authority that the Federal Power Act lodges in the Commission, I would add these filing requirements to our approval of the rates Doswell brings here. The state needs the information to make our monitoring work better and I think we can use all the help parties offer.

I would prefer the order contain these suggestions, but, in any event, I concur in approving Doswell's rate filing.

APPENDIX E

Order of the Virginia State Corporation Commission (February 26, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

At Richmond, February 26, 1988

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc., in Altavista, Virginia

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Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEM, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, in Hopewell, Virginia

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Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEM, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc., in Buena Vista, Virginia

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Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc., in Franklin, Virginia

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Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INC.

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc., in Covington, Virginia

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Case No. PUE870096

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Mineral Management Systems, Inc., in Algoma, West Virginia

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Case No. PUE870097

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION AND FCS DEVELOPMENT CORP.

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Davis, West Virginia

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Case No. PUE870099

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for two small power production facilities located at United Coal Company at Big Rock, Virginia and Richlands, Virginia

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ORDER

Oral argument on these matters was heard by the Commission on February 25, 1988. The parties and the Staff were ably represented by counsel, and their respective positions were clearly enunciated. The Commission found this argument very helpful in reaching its decision.

The Commission will not engage in a lengthy recapitulation of the issues, or of the positions taken thereto. Rather, we shall proceed to enunciate succintly our conclusions.

These 8 cases are part of the fourteen pending petitions for arbitration representing approximately 759 megawatts of capacity.

These petitions were filed by the qualifying facilities against Virginia Power in reliance upon our orders of January 11, 1983, in Case No. PUE800102, and November 15, 1985, in Case No. PU830067.[1] That reliance was not misplaced. By this order the Commission announces that it will arbitrate to a conclusion those

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[1] In those orders, the Commission held that, for large qualifying facilities, it would arbitrate disputes among parties who otherwise were unable to reach acceptable contractual arrangements. We found that such action was an appropriate means of implementing § 210 of PURPA and the associated federal regulations. Those regulations provide, *inter alia*, that State commissions may comply with the PURPA mandate by "undertaking to resolve disputes between qualifying facilities and electric utilities. . . ." 18 CFR § 292.401(a).

legitimate disputes pending and ripe for arbitration as of the date of this order, and will do so in a fair and expeditious manner, with the expected cooperation of the parties.

Arbitration is an arrangement for resolving a disputed matter which is an alternative to the formalities of established legal tribunals and litigation. The Commission intends to approach these arbitrations in an innovative fashion, designed to deal with the subject in the prompt, but effective, manner that it warrants. In this light, it is inappropriate for the Commission to sit as a body conducting its traditional quasi-judicial or legislative proceedings. Instead, the Commission, pursuant to PURPA procedures and the implementing regulations thereto, hereby designates Commissioner Thomas P. Harwood, Jr. to serve as arbitrator in these petitions.

We expect the outcome of this arbitration to develop specific terms and conditions of appropriate contracts for capacity purchases by Virginia Power from petitioners. The actions of Commissioner Harwood, and the conclusions he reaches, will be final. The outcome will be binding on Virginia Power in that the utility will be required, pursuant to its obligations under PURPA, to execute those contracts found to be reasonable by the arbitrator. His actions will likewise be binding on the qualifying facility if it expects to contract with Virginia Power in these cases. PURPA, of course, imposes no *obligation* on cogenerators to sell their capacity or energy.

Our order of January 29, 1988, in Case No. PUE870080, promulgated no rules and mandated no course of action to be followed by Virginia electric utilities in acquiring generating capacity from qualifying facilities. That order did identify "bidding" by potential cogenerators as an acceptable means of complying with PURPA, but the decision to use such a procedure, and the process of selecting from among the actual bidders, is left to the utilities. We suggested, however, that the

utilities consider what we termed "competitive negotiation."

Competitive negotiation envisions the issuance by the utility of a form of "Request for Proposals" ("RFP"), and we outlined some suggested factors, or criteria, which might be incorporated in an RFP. The factors would be expected to vary from time to time, depending on both internal and external conditions.

Virginia Power is not precluded at this time from proceeding to solicit additional generating capacity by means of some version of an RFP. It must be understood, however, that further solicitation at this time shall be subject to the outcome of the arbitration herein provided. That is, the amount of capacity potentially to be contracted for under any RFP will be limited by the amount of capacity for which contracts have been executed as a result of the arbitration process. Should Virginia Power decide to go forward with its previously announced efforts, the petitioners may freely participate therein without fear of prejudicing the arbitration processes at this Commission. The desirability of such dual participation is a matter for their determination.

ATTESTED COPIES of this order shall be mailed to Richard D. Gary, Esquire, P.O. Box 1535, Richmond, Virginia 23212; John E. Cunningham, Esquire, Manager-Regulation Services, Virginia Power, P.O. Box 26666, Richmond, Virginia 23261; Edward L. Flippen, Esquire, Mays & Valentine, P.O. Box 1122, Richmond, Virginia 23208-9970; and to the Commission's Directors of Energy Regulation and Economic Research and Development and the General Counsel.

A True Copy:

Teste:

/s/ George W. Bryant, Jr.
Clerk of the
State Corporation Commission

APPENDIX F

Decision on Pricing Issue, Thomas P. Harwood, Jr., Virginia State Corporation Commission (April 27, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

April 27, 1988

Richard D. Gary, Esq.
Hunton & Williams
P.O. Box 1535
Richmond, Virginia 23212

James C. Roberts, Esq.
Mays & Valentine
P.O. Box 1122
Richmond, Virginia 23208-9970

Re: Virginia Power and Ultra Cogen Systems Arbitration. Case Nos. PUE870088 et al.

Gentlemen:

Enclosed is my decision on the pricing issue. The memoranda and oral argument were most helpful, and for them I thank counsel.

The negotiation sessions may now progress, and they should be held more often than once a week.

I expect to meet briefly with counsel at 9:00 a.m. this Friday, April 29, and at 4:00 p.m. on Friday, May 6. Status reports will continue to be due by 5:00 p.m. on April 29 and May 6.

The parties should amicably resolve any remaining issues.

Sincerely,

/s/ Thomas P. Harwood, Jr.
THOMAS P. HARWOOD, JR.

TPHjr:lmc

cc: Edward L. Flippen, Esq.
John E. Cunningham, Esq.
William G. Thomas, Esq.
William S. Bilenky, Esq.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

MEMORANDUM

DATE: April 27, 1988

TO: James C. Roberts, Esquire
Edward L. Flippen, Esquire
Richard C. Gary, Esquire
William G. Thomas, Esquire
John E. Cunningham, Esquire

FROM: Thomas P. Harwood, Jr., Arbitrator

RE: Pricing Issue, Virginia Power and Ultra Cogen Systems ("UCS"), Case Nos. PUE870088, et al.

In seeking to discharge my responsibilities as arbitrator in these matters, pursuant to my appointment by Order of the State Corporation Commission, dated February 26, 1988, I have carefully considered the record in this proceeding. That record includes the briefs of the parties, and the Attorney General as *amicus*, followed by oral argument on April 25, 1988, in which the parties debated for my benefit the very fundamental issue in this arbitration of how to calculate the appropriate payments to UCS for the power it expects to deliver to Virginia Power from its proposed generating facilities. It seems agreed that I am to resolve the stalemate on this point by directing a suitable methodology to be followed.

In seeking to surmount this pricing hurdle, I have also had the benefit of the discovery materials exchanged between the parties, the previous meetings I have held with them, and the minutes and progress reports of those work sessions which were held by the parties, alone, at my direction. I have also reviewed the Notices of Proposed

Rulemaking of the Federal Energy Regulatory Commission which were issued on March 16, 1988, in Docket Numbers RM88-5-000 (Regulations Governing Bidding Programs) and RM88-6-000 (Determination of Avoided Costs), together with the Final Report of the Commission's Avoided Cost Task Force, dated October 8, 1987.

An evaluation of the foregoing leads me to the following findings and conclusions:

I first find that the UCS projects are entitled to a determination of avoided cost payments as of November 12, 1987, the date on which UCS began to file its arbitration petitions with the Commission. Short of a written contract, which does not exist even now, and which is not a necessary prerequisite to the commencement of the purchase obligation under PURPA, see *Snow Mountain Pine Company vs. Maudlin,* 734 P.2d. 366 (Or.App. 1987), the filing of these petitions constitutes the latest possible date on which UCS became "obligated" to provide power to Virginia Power, in the sense that that term is used in PURPA.

I next find that avoided cost payments should be based on Virginia Power's costs of constructing and operating Chesterfield Unit No. 7, as projected on that same date, November 12. It has been the posture of Virginia Power for some time that Chesterfield 7, a gas-fired plant, could, and should, serve as a basis for the Company's avoided cost calculations since that unit is intended to be the prototype of any new capacity to be built by the Company through the mid-1990's, and perhaps beyond. See, *Application of Virginia Electric and Power Company* (Chesterfield 7 approval), Case No. PUE860058, Transcript, June 17, 1987, pp. 642-643.

The minutes of the parties' meeting on April 19, 1988, also contain a statement from Virginia Power that "its costs to construct, own, and operate a facility similar to Chesterfield 7 would represent a cap on avoided costs".

Finally, Virginia Power's recent claims that UCS's proposal would cost ratepayers some $2.0 billion "more" over a 25-year life cycle was apparently tied closely to figures related to Chesterfield 7 and the Company's December 23, 1986, solicitation which was based on those figures.

In making this decision, I am, of course, rejecting Virginia Power's position that the results of the bidding procedure currently underway should serve to determine appropriate avoided costs. I find this position untenable. As noted above, UCS's legal entitlement to an avoided cost contract arose as of November 12, 1987. By contrast, the figures related to Virginia Power's proposal are not known even today, and will not be known for some time. This matter must be resolved now, however, and not at some indefinite future date. I further find that adoption of Virginia Power's proposal herein would be contrary to the Order of the Commission, dated February 26, 1988.

The gas-fired Chesterfield 7 scenario is thus to serve as the determinative factor for avoided costs. The calculation of exact amounts to be paid for energy and capacity using this methodology will, of course, be the responsibility of the parties, which I expect to be discharged promptly by the devotion of all necessary resources. In this endeavor, we are all mindful that there will be differences in the operational parameters of UCS's coal-fired plants, as compared to Chesterfield 7. For example, a coal plant, with lower fuel costs, will presumably have a higher capacity factor and will be utilized on the system on a more frequent basis than a gas plant. In this respect, I call attention to the statement made at the April 19, 1988, meeting that "the critical issue is the projects' effect on total system cost, and the division of the total payment stream from Virginia Power between energy and capacity is generally up to Ultrasystems".

In determining fair payment—consistent with PURPA—I would suggest that it should be useful to develop

various life-cycle revenue streams associated with Chesterfield 7, assuming differing capacity factors such as 60%, 70%, or 80%, with the costs awarded to these coal plants being based on the most likely of those scenarios for the particular projects. The ultimate objective, of course, is that ratepayers pay no more over the life of these plants than they would have paid had the need been supplied by facilities like Chesterfield 7, in lieu thereof, taking into account the differing capacity factors attributable to coal plants, and recognizing that, as more coal plants are added, they will begin to take on the characteristics of base-loaded facilities, rather than the more lightly-loaded design features of Chesterfield 7.

Finally, the parties should *not* understand this decision to be an approval of the December 23, 1986, so-called "solid fuel offer." The minutes of the April 19, 1988, meeting appear to me to demonstrate that the latter was not equivalent to the Chesterfield 7 plant, itself. Rather, my decision is to focus on *Chesterfield 7* and the appropriate equivalent payment streams arising out of the projected figures associated with that plant, and an emphasis on the solid-fuel offer would not be a suitable means of complying with this directive.

With this pivotal issue resolved, I see no reason why the parties cannot now move to a mutually successful conclusion of these negotiations. I expect to be fully and promptly apprised of any further sticking point, but I am determined that there shall be no unjustified delays.

/s/ T. P. H.

cc: William S. Bilenky, Esquire

APPENDIX G

Interim Order of the Virginia State Corporation Commission (May 27, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc. in Altavista, Virginia

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Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, Hopewell, Virginia

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Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc. in Buena Vista, Virginia

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Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Franklin, Virginia

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Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Covington, Virginia

---

Case No. PUE870096

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Mineral Management Systems, Inc. in Algoma, West Virginia

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Case No. PUE870097

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION AND FCS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Davis, West Virginia

---

Case No. PUE870099

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for two small power production facilities located at United Coal Company, at Big Rock, Virginia and Richland, Virginia

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INTERIM ORDER

Ultra Cogen Systems, Inc. and Ultrasystems Development Corporation (collectively "UCS") filed these Petitions for Arbitration between November 12, 1987 and December 3, 1987 requesting the Commission to order Virginia Power to enter into power purchase agreements with UCS. Virginia Power opposed the Petitions. By Order dated February 26, 1988 the Commission found that UCS properly relied on earlier Commission orders and designated that I should serve as arbitrator with regard to those Petitions that represented legitimate disputes pending and ripe for arbitration as of February 26, 1988.

Under my direction, representatives of UCS and Virginia Power initiated negotiations to narrow, if not eliminate, the issues that stand between the parties and the execution of power purchase agreements for the facilities underlying the Petitions for Arbitration. The negotiations were stymied by a disagreement as to the fundamental issue of how to calculate the appropriate payments to UCS for the capacity and energy it expects to make available to Virginia Power from UCS' proposed generating facilities. To resolve that issue, I required a hearing on April 25, 1988 and issued my opinion on April 27, 1988. In essence, I required the pricing proposal to be based on Virginia Power's cost of constructing and oper-

ating Chesterfield 7 as those costs were projected on the first date these Petitions for Arbitration were filed, November 12, 1987. I required that consideration be given to the capacity factors projected for the UCS units and Chesterfield 7 and my objective was that Virginia Power's ratepayers should pay no more over the life of these UCS generating facilities than they would have paid had the need been supplied by facilities like Chesterfield 7.

The proper payments that respond to my directive of April 27, 1988 are contained in Attachment A to this Interim Order, along with other key terms and conditions that should be included in a power purchase agreement between the parties. I direct that these provisions in Attachment A, which I find to be required by the Commission's and my earlier rulings, must be reduced to written agreements. I shall leave these dockets open until the power purchase agreements have been finalized so that I may review their terms and conditions to assure that they comply fully with our mandates in these proceedings. The parties should notify me when such final power purchase agreements have been reached, and I will review these agreements. The parties have also agreed that the number of UCS projects to be considered by the Commission should be reduced to four and, upon entry of the final order, UCS shall withdraw the Petitions for Arbitration in Case Nos. PUE870096, PUE870097 and PUE870099. Further such final order will contain a provision requiring UCS within a period of 6 months after its entry to withdraw one additional Petition. I shall issue final orders in all of these proceedings at the appropriate time consistent with this Interim Order.

/s/ Thomas P. Harwood, Jr.
THOMAS P. HARWOOD, JR.

May 27, 1988

ATTACHMENT A

RESOLUTION OF MAJOR ISSUES ULTRASYSTEMS PROJECTS

1. *Pricing*

   a. *Capacity Price*

   For each of the four projects, the Capacity Price shall be $341.23 per dependable kilowatt for the first 15 years of operation and $189.70 for years 16 through 25.

   b. *Energy Price*

   (1) *Base Price.* The average energy price in 1991 dollars for four projects shall be 2.192 cents/kwh, inclusive of variable operating and maintenance expenses and line losses. Distribution among the projects shall be at Ultrasystems' discretion.

   (2) *Escalation.* During the first 8 years of commercial operation, energy prices will be escalated at 4.1% per annum. On or before the eighth anniversary of commercial operation, the parties will agree to a new base energy price to be effective on said eighth anniversary, which base price will reflect the actual escalation which occurred over the preceding 8 years. At that time, the parties will also agree to market (not in-system coal) based index or series of indexes to be used thereafter. The base price and escalation index(es) shall be reexamined every three years thereafter to reflect actual market conditions.

   c. *Capacity Price Adjustment*

   The Capacity Price in years 16-25 will be adjusted upward or downward by $5.00/kw for

every tenth of a percent that the rate of inflation, as determined by the compounded annual change in the GNP Implicit Price Deflator, exceeds 5.3 percent or is below 4.3 percent, respectively during years 1-15 of the term of the agreement.

2. *Dispatchability*

The facilities will be subject to economic dispatchability, consistent with the following design limits:

(a) Maximum output is 57 MW for Buena Vista, Covington and Hopewell; 55 MW for Franklin and Altavista.

(b) Minimum ramp time is 200 kw/minute up; 500 kw/minute down.

(c) Minimum run time between shutdowns is 12 hours; cannot change direction of dispatch more than twice in any 24 hour period or shut down more than 40 times per year.

(d) Minimum load is 35% of maximum.

(e) Notices: Minimum 8 hours for cold start or full shutdown; 15 minutes for all others; second notice of 30 minutes before forced outage begins.

3. *Forced Outage Damages*

At the end of each agreement year, the actual availability of each facility will be determined, based on the number of hours of forced outage (excluding force majeure) with failure to respond to dispatch after second notice within 5% being considered a forced outage. For each hour for which the facility is unavailable, after an allowance for scheduled outage hours (30 x 24) and an allowance for free forced outage hours (33.5 x 24), Ultrasystems will refund the annual Capacity Payment pro rata at the

rate of 1.5 hours for every hour of such excess outages until such excess outages exceed 50% of total hours in excess of the free forced outage allowance, at which point the entire Capacity Payment for the year will be refunded. Refunds will include interest.

4. *Force Majeure*

Upon declaration of a Force Majeure by Ultrasystems, Virginia Power may immediately suspend Capacity Payments for the duration in days of the Force Majeure. Ultrasystems may, however, choose to use all or any portion of its free forced outage allowance for all or any portion of the Force Majeure days.

5. *Capacity Reduction Damages*

a. *Commercial Operation.*

If, upon commercial operations testing, a facility's actual capacity is less than 90% of the maximum capacity specified in 2 above, Ultrasystems shall pay $15 per kw for the difference below said 90% level.

b. *Seasonal*

If, upon seasonal testing, the capacity is below 85%, Ultrasystems will pay 21.60 per kw below 85% prorated daily. Ultrasystems may call for retests without penalty, but no more often than once in 30 days.

6. *Security*

a. *Pre-Commercial Operation*

(1) A letter of credit or other security reasonably acceptable to Virginia Power, in the amount of $5/kw for each facility. will be posted on the later of 6 months from the

execution of the letter agreement or 60 days from execution of the final contract.

(2) The security instrument shall be increased to $10/kw on the earlier of financial closing or 9 months from posting security pursuant to (1) above.

(3) It shall be increased to $15/kw, 6 months after (2) above.

(4) Damages for abandonment are liquidated at amount of security at all times, subject to Force Majeure, except that the $5.00 amount referred to in 6(a)(1) is not subject to Force Majeure or any other contingencies. If commercial operation is delayed more than 6 months, damages are liquidated at 1/12 of security per month for each month of delay thereafter.

b. *Operations*

Pre operations security remains in effect for entire term to cover liquidated damages.

7. *Regulatory Out (Article 18)*

Will be removed from contracts, assuming entry of the contemplated order directing the rates and terms of the contracts.

8. *QF Certification*

Ultrasystems' obligation to maintain QF status is limited to existing criteria and procedures. If significant new criteria or procedures applicable to the facilities are enacted, compliance will not be a condition of the contract.

9. *Interconnection Costs*

Will be borne by Ultrasystems.

10. *Ownership Transfers*

Before transferring a significant (10% or greater) ownership interest other than for financing purposes, Ultrasystems will first offer it to Virginia Power at a price proposed by Ultrasystems. If Virginia Power does not accept within 60 days, Ultrasystems may offer it to others at a price equal to or greater than the proposed price.

11. *Number of Projects*

Agreements shall be entered into for 4 projects within Virginia Power's service territory, with provision for Ultrasystems to substitute projects in at least one agreement, so that Ultrasystems is not required to elect among the 5 proposed projects until 6 months after execution of the Agreements.

12. *Other*

The parties shall use all reasonable efforts to reach final contractual agreement within 60 days, and neither party shall raise any major substantive issue inconsistent with the above or not raised in the markups exchanged on April 15, 1988 and May 11, 1988.

APPENDIX H

Award and Final Order of the Virginia State Corporation Commission (September 30, 1988)

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

At Richmond, September 30, 1988

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc. in Altavista, Virginia

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Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, Hopewell, Virginia

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Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc. in Buena Vista, Virginia

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Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Franklin, Virginia

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Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Covington, Virginia

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Case No. PUE870096

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Mineral Management Systems, Inc. in Algoma, West Virginia

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Case No. PUE870097

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION AND FCS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for a small power production facility located at Davis, West Virginia

---

Case No. PUE870099

PETITION OF ULTRASYSTEMS DEVELOPMENT CORPORATION

For arbitration of a contract with Virginia Electric and Power Company for two small power production facilities located at United Coal Company, at Big Rock, Virginia and Richland, Virginia

---

Award And Final Order

Ultra Cogen Systems, Inc. and Ultrasystems Development Corporation (collectively "UCS") filed these petitions for arbitration between November 12, 1987, and December 3, 1987, requesting the Commission to order Virginia Power to enter into power purchase agreements (Agreements) with UCS. The Commission ordered Virginia Power on December 18 to file responsive pleadings, and on December 31 Virginia Power filed its responses opposing the petitions.

On January 29, 1988, the Commission entered a final order in *Commonwealth of Virginia At the Relation of the State Corporation Commission Ex Parte, In the matter of adopting Commission Policy regarding the purchase of electricity by public utilities from qualifying facilities*

when there is a surplus of power available, Case No. PUE870080, expressing general approval of the concept of competitive bidding for new power supplies. Relying in part on that final order, Virginia Power filed on February 11, 1988, a motion to dismiss the UCS petitions for arbitraiton. On February 19 the Commission entered an order in this docket scheduling oral argument on the effects of the final order in Case No. PUE870080 on the Commission's previous decisions delineating the relationship between Virginia utilities and qualifying cogeneration facilities and on the UCS petitions for arbitraton.

After hearing oral argument from both parties on February 25, the Commission entered an order on February 26 stating that the Commission would "arbitrate to a conclusion those legitimate disputes pending and ripe for arbitration as of the date of this order." The Commission noted that it intended "to approach these arbitrations in an innovative fashion." By the same order, the Commission designated that I serve as arbitrator with regard to those petitions that represented legitimate disputes pending and ripe for arbitration as of February 26, 1988. My assigned task has been "to develop specific terms and conditions of appropriate contracts for capacity purchases by Virginia Power from petitioners."

Virginia Power and UCS exchanged interrogatories throughout March and April and began moving towards agreement on terms and conditions. Despite their progress, however, the parties disagreed on a fundamental level with respect to pricing and related issues, and they reached an impasse.

On April 20, 1988, both parties, along with the Office of the Attorney General, filed briefs on the pricing and related issues. Virginia Power supported prices based on avoided costs as determined according to the results of its solicitation of competitive bids. UCS argued that prices should be based on avoided costs as determined according to the Commission-approved methodology in

place as of the time UCS obligated itself to supply power to Virginia Power. I rendered my decision in a letter to the parties dated April 27, 1988.

I required the pricing proposal to be based on Virginia Power's costs of constructing and operating Chesterfield 7 as those costs were projected on the first date these petitions for arbitration were filed, November 12, 1987. The ruling required that consideration be given to the capacity factors projected for the UCS units and Chesterfield 7, and the objective was that Virginia Power's ratepayers should pay no more over the life of the UCS generating facilities than they would have paid had the need been supplied by the Company.

In an interim order dated May 27, 1988, I set forth in Attachment A to that interim order the proper payment structure and other key terms and conditions that should be included in the Agreements. I found that the provisions were required by the earlier orders in these proceedings. The interim order noted that the parties had also agreed that only the projects within Virginia Power's territory would be considered by the Commission and that the number of projects would be reduced to four. To assure that only four projects would be the subject of final Agreements between the parties, I found that upon the conclusion of this proceeding, UCS should withdraw immediately the petitions for arbitration in Case Nos. PUE870096, PUE870097, and PUE870099 and that within 6 months after the entry of this Award and Final Order, UCS should eliminate one additional project, thus assuring that only four projects are the subject of final Agreements between the parties. Finally, I issued a second interim order dated September 2, 1988, noting that the parties had reached agreement on all aspects of the Agreements except for the designation of the specific escalation index or indices to be used to adjust the energy price after the eighth year of commercial operation. I requested that the parties finalize the Agreements by

September 23, 1988, and submit them to me by September 26, 1988.

I received a letter from Virginia Power advising me that, although the parties had reached agreement on all issues, a drafting error would prevent them from filing the final Agreements until September 30, 1988.

In accordance with that letter, the parties submitted to me on September 30, 1988, four identical proposed Agreements that required UCS to choose, within six months of the date of this Award and Final Order, the four projects which are to be the subject of the Agreements. I have reviewed the Agreements submitted by the parties on September 30, 1988, and find that they comply with the provisions of Attachment A of the first interim order, are reasonable and in the public interest, and are required by the Commission's and my earlier orders in this proceeding. I recognize that the Agreements reflect negotiations and rulings based on the unique circumstances of these proceedings (including that they are coal-fired cogeneration facilities in lesser populated areas of the Commonwealth), and I commend the parties for their diligent efforts.

I order that Virginia Power execute the four Agreements submitted to me on September 30, 1988 and deliver the same to UCS for execution within one week following the entry of this Award and Final Order. I further order that UCS select the four projects to which the Agreements are to apply within six months from the date of this Order in accordance with the third recital of the Agreements and that Virginia Power designate the applicable Operations Center and Virginia Power office for each project within thirty days thereafter in accordance with the fourth recital of the Agreements.

I order that these Agreements be placed in the Commission's public files on March 1, 1989, along with all other contracts executed during 1988 for power purchases

from qualifying facilities or independent power producers as required by the Commission's orders in Case Nos. PUE800102 and PUE830067.

/s/ Thomas P. Harwood, Jr.
THOMAS P. HARWOOD, JR.

Dated: September 30, 1988

APPENDIX I

Order of the Virginia State Corporation Commission Ending Proceedings (November 18, 1988)

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

At Richmond, November 18, 1988

Case No. PUE870088

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at The Lane Co., Inc. in Altavista, Virginia

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Case No. PUE870089

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Firestone Tire and Rubber Company, Hopewell, Virginia

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Case No. PUE870090

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Georgia Bonded Fibers, Inc. in Buena Vista, Virginia

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Case No. PUE870091

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Franklin, Virginia

Case No. PUE870092

PETITION OF ULTRA COGEN SYSTEMS, INCORPORATED

For arbitration of a contract with Virginia Electric and Power Company for a cogeneration facility located at Hercules, Inc. in Covington, Virginia.

ORDER ENDING PROCEEDINGS

Commissioner Thomas P. Harwood, Jr. entered an Award and Final Order in this proceeding on September 30, 1988. The Commission hereby ratifies and adopts such Order as the Final Order in this proceeding and there appearing nothing further to be done in these proceedings hereby orders that these matters be dismissed from the docket and the papers placed in the file for ended causes.

ATTESTED COPIES of this order shall be mailed to Richard D. Gary, Esquire, P. O. Box 1535, Richmond, Virginia 23212; John E. Cunningham, Esquire, Manager-Regulation Services, Virginia Power, P. O. Box 26666, Richmond, Virginia 23261; Edward L. Flippen, Esquire, Mays & Valentine, P. O. Box 1122, Richmond, Virginia 23208-9970; William S. Bilenky, Esquire, Senior Assistant Attorney General, Office of the Attorney General, 101 North 8th Street, 6th Floor, Richmond, Virginia 23219; and to the Commission's Directors of Energy Regulation and Economic Research and Development and the General Counsel.

A True Copy

Teste:

/s/ George W. Bryant, Jr.
Clerk of the State
Corporation Commission

APPENDIX J

**Exerpts from the Federal Power Act,
16 U.S.C. §§ 824, 824a-3**

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16 U.S.C. § 824:

Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities

used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter. . .

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

* * * *

16 U.S.C. § 824a-3:

Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to. . .

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities and;

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies

having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views and arguments. . . . Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric eneregy. . . .

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

APPENDIX K

Excerpts From Regulations Under the Public Utility Regulatory Policies Act of 1978, 18 CFR Part 292 (1987)

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18 CFR § 292.101(b)(6) (1987):

§ 292.101 Definitions.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

18 CFR § 292.303(a) (1987):

§ 292.303 Electric utility obligations under this subpart.

(a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility[.]

18 CFR 292.304 (1987):

§ 292.304 Rates for purchases.

(a) Rates for purchases.

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) Relationship to avoided costs.

(1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) Standard rates for purchases.

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.303(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting for variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

18 CFR § 292.401 (1987):

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) State regulatory authorities. Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilitates and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

APPENDIX L

Order of the Virginia State Corporation Commission (January 11, 1983)

VIRGINIA STATE CORPORATION COMMISSION

Case No. PUE800102
(and former Case Nos. PUE800082 and PUE800083)

January 11, 1983

Commonwealth of Virginia, ex rel.

Ex Parte, in re: Implementation of Federal Rules concerning Cogeneration (and Small Power Production Facilities pursuant to § 210 of the Public Utility) Regulatory Policies Act of 1978 for Virginia Electric and Power Company

FINAL ORDER

Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") mandated that the Federal Energy Regulatory Commission ("FERC") prescribe rules to encourage cogeneration and small power production within one year after its enactment on November 9, 1978. Further, it required that the Commission, after notice and opportunity for public hearing, implement the FERC rules for each electric utility for which it has ratemaking authority within one year from the promulgation of the FERC's rules.

Although the aforementioned rules had not yet been implemented by the Commission, Virginia Electric and Power Company ("Company") filed a proposed Schedule 10 on June 19, 1980, applicable on a voluntary basis to the supply and/or purchase of electricity to or from

any customer with cogeneration or small power production facilities (Case No. PUE800082). On June 20, 1980, Company filed a revised Rider I For Residential Customers—Standby, Parallel, or Small Power Producer Service (Case No. PUE800083).

Company filed a revised Schedule 10 in Case No. PUE800082 on July 8, 1980, which had been amended to reflect the new fuel factor established by Commission order filed June 27, 1980. On October 3, 1980, Company filed another revised Schedule 10 designed to conform to the rate increase in Schedule 6 granted by the Commission in Company's Review of Financial Operations on September 12, 1980 (Case No. PUE800056). This revised tariff was accepted for filing and the public notice requirements were waived by Commission order dated October 22, 1980.

Company filed another revised Schedule 10 on October 23, 1980, which was designed to reflect the changes in base rates and the fuel factor resulting from the initiation of commercial operation of the North Anna Unit No. 2 (considered in Case Nos. PUE790011 and PUE800067). This revised tariff was accepted for filing and notice requirements were waived by Commission order dated November 25, 1980, in Case No. PUE800082.

Pursuant to PURPA § 210 the Commission entered an order on November 20, 1980, establishing the present case (Case No. PUE800102) for the purpose of determining appropriate rates and provisions for cogeneration and small power production facilities under said section for Company. By the same order, the Commission scheduled a public hearing for January 26, 1981, and directed Company to file proposed rates and information relating to the development of rates pursuant to § 210.

On December 19, 1980, Company filed Schedule 12 —Power Purchases From and Sales to Cogenerators and Small Power Producers. This new proposed schedule was intended to be a voluntary rate schedule applying to cus-

tomers with generating facilities designated as new capacity as defined by 18 C.F.R. 292.304(b)(1).

A public hearing was held before Stewart E. Farrar, Hearing Examiner, on January 26 and 27, 1981, in the Commission's Courtroom, Jefferson Building, Richmond, Virginia. Counsel appearing were: Evans B. Brasfield, Esquire, Richard D. Gary, Esquire, and Douglas M. Palais, Esquire, for Company; Walter A. Marston, Jr., Esquire, and Sally Y. Wood, Esquire, for the Virginia Hydro Power Association; A. C. Epps, Esquire, and Charles F. Midkiff, Esquire, for the Virginia Committee for Fair Utility Rates; Eric M. Page, Esquire, for the Division of Consumer Council, Office of the Attorney General; Patricia M. Schwarzschild, Esquire, for Westvaco; and Donald G. Owens, Esquire, for the Commission. Six interveners appeared at the hearing.

On February 5, 1981, Company filed revised schedules, testimony, and exhibits for the purpose of correcting its earlier filing. Public notice, a public hearing, and consideration by the Commission of these revised schedules became unnecessary because of findings made by the Commission based on the evidence received in the January 26 and 27, 1981, public hearing.

On March 16, 1981, the Hearing Examiner filed his report. Subsequent to that date, Company, the Attorney General, Westvaco, Virginia Hydro Power Association, and Continental Forest Industries filed exceptions to the report.

On June 18, 1981, the Commission issued an Interim Order in this proceeding which contained the following findings:

(1) That each Qualifying Facility ("QF") with a design capacity exceeding 100 kw should negotiate the terms of its sale of electricity with Company and that the Commission will stand ready to arbitrate in the event that an agreement cannot be reached;

(2) That a single cogeneration schedule should be established for QFs having a design capacity of 100 kw or less, and that no distinction should be made between "old" and "new" capacity under such schedule;

(3) That Company's cogeneration schedule should provide that each QF has the option of either a simultaneous purchase and sale transaction or the sale only of its excess power; selection of such option shall be expressed in its contract and shall be for a period of not less than one year;

(4) That Company's cogeneration schedule should provide that those QFs willing to forego any capacity payments have the option to use only a time-differentiated kilowatt hour meter for measuring purchases of energy by the utility;

(5) That Company's cogeneration schedule should provide that those QFs who are willing to forego any capacity payments and are willing to be paid for all energy at off-peak rates should have the option to use only a standard single register kilowatt hour meter to measure energy purchased by the utility;

(6) That Company's cogeneration schedule should state that those customers desiring to provide power without reimbursement to Company are allowed to do so; in such instances, Company should only require the installation of a detent to prevent the customer's meter from running in reverse;

(7) That Company should define interconnection costs in its tariff as such costs are defined by FERC Rule, 18 CFR § 292.101(7), and that such costs should be repaid at the time of installation or over a period of up to 3 years, at the option of the QF, or over such longer period as may be mutually agreeable to the parties;

(8) That, in cases in which QFs pay interconnection costs over a period of time, Company should be allowed

to collect interest, the rate of such interest not to exceed the cost of Company's most recent issue of long term debt;

(9) That, in the event that any QF chooses to repay interconnection costs over a period of years, Company may require security for repayment;

(10) That Company's delineation of peak and off-peak periods is reasonable for the purpose of this proceeding;

(11) That Company's cogeneration schedule should provide that the payment of capacity credits will commence at the beginning of each contract term, and should be based upon the best available evidence at that time (such capacity credits may be revised on an annual basis);

(12) That the criteria for payment of capacity credits in Company's schedule should be expanded to include those found in FERC Rule § 292.304(e)(2)(vi) and (vii); that capacity credits should be available to QFs of any size or configuration which are willing to contract to supply capacity, and that Company's proposed capacity credits are reasonable;

(13) That Company should recalculate its avoided energy costs in accordance with the suggestions in Mr. Wittine's testimony;

(14) That Company's proposal to discount avoided costs for administrative expenses and unknown costs cannot be justified on the present record;

(15) That Company's proposal to include customer charges cannot be justified on the present record;

(16) That new notice and an additional hearing is required before this Commission can determine the reasonableness of Company's most recently proposed avoided costs;

(17) That Company's cogeneration schedule should provide that QFs are able to purchase power at any applicable retail rate;

(18) That Company should revise its cogeneration schedules in accordance with the findings herein and its most recent calculation of avoided costs, and that, during the period between the date of this order and any final determination regarding cogeneration schedules, that Company should negotiate temporary agreements with cogenerators that would be covered by such schedule; in the event that any agreements cannot be reached, the Commission stands ready to arbitrate differences;

(19) That Company should submit data to the Commission as recommended by Staff witness Wittine;

(20) That the findings made herein are limited to the record developed in this case.

In the June 18, 1981, Interim Order, the Commission ordered Company to file tariffs on or before July 1, 1981, in accordance with the findings listed above. The Commission also ordered Company to file the following data with the Commission on or before March 1 of each year beginning March 1, 1982, (such data to cover the 12 months ending the previous December 31):

The name and location of each QF interconnected with Company;

The design capacity of each QF;

The amount of energy purchased from each QF;

The amount of energy sold to each QF;

Copies of any contracts entered into between Company and QFs;

Avoided costs data of the type required by 18 CFR § 292.302.

The July 1, 1981, date for filing revised tariffs was later extended by Commission order dated June 26, 1981. Company filed a proposed Schedule 19 designed to replace its previously proposed Schedules 10 and 12 on August 14, 1981.

On December 8, 1981, the Commission filed an order setting a public hearing to be held on February 26, 1982, and requiring additional public notice.

The public hearing on February 26, 1982, was presided over by Stewart E. Farrar, Hearing Examiner. Counsel appearing were: Richard D. Gary, Esquire, and Douglas M. Palais, Esquire, for Company; A. C. Epps, Esquire, for the Virginia Committee for Fair Utility Rates; Stephen H. Watts, II, Esquire and John J. Carrara, Esquire, for Westvaco; Eric M. Page, Esquire, for the Division of Consumer Counsel, Office of the Attorney General; and Donald G. Owens, Esquire, for the Commission. Four intervenors testified at the hearing.

On April 19, 1982, the Hearing Examiner filed his report. The Hearing Examiner found that the proposed Schedule 19 complied with the Commission's June 18, 1981, Interim Order and that, subject to one qualification, Schedule 19 presented a just and reasonable method of regulating the purchases by Company of electrical energy from qualifying cogenerators and small power producers operating facilities with designed capacities of 100 kw or less. The reason for the Hearing Examiner's qualification of his approval concerned Company's charges for interconnection costs. The Interim Order of June 18, 1981, specified that the cost of interconnecting qualifying facilities with the system grid could be repaid at the time of installation, or over a period of up to three years, at the option of the qualifying facility, or over longer periods if mutually agreeable. The Order permitted reasonable interest and security for repayment to be required from those electing to spread payments over time.

Company incorporated these provisions in its tariff, Paragraph V(B) of Schedule 19, but also established a monthly charge equal to 0.75 percent of the cost of the required installation. (The tariff provides that Company will be the owner of all such facilities.) Such recurring charge would be paid by the customer whether its interconnection costs were paid immediately or over a period of years.

A Company witness testified that this monthly charge was intended to cover the operation and maintenance costs of the facilities in question, as well as the amortized cost of eventually replacing the equipment. The Hearing Examiner noted that it appeared somewhat inconsistent that the customer would have to pay the full costs of installing such equipment initially, and then immediately begin paying a fractional portion of such costs with his very next monthly bill. The Examiner suggested that a more uniform method would be to charge the customer for the costs of installation initially, and then to assess him for the full cost of any replacement facilities, if and when needed. The monthly charge would then cover only insurance, property taxes, and operation and maintenance of the facilities.

Although the Hearing Examiner noted that he was willing to recommend approval of Schedule 19 as proposed because he considered the above issue to be a rather minor one and because the proposed tariff does follow the practice established in Company's general terms and conditions, the Hearing Examiner asked Company to respond to his suggestion if it had serious objections to the proposed alternative.

Company filed a response to the Hearing Examiner's Report on May 4, 1982. In its response Company, after noting that both approaches to payment for interconnection costs have merit, suggested that, "as a third alternative, it may be appropriate to give each qualifying facility the option of paying a monthly charge which includes the

cost of eventual replacement or a monthly charge which does not include such cost." If the latter alternative is chosen, the qualifying facility would be responsible for the full cost of replacement of interconnection facilities at the time such replacement is required. Company also suggested that, if this third alternative is adopted by the Commission, the option should be a one-time option selected at the outset of construction of interconnection facilities, and should be binding on all future owners and operators of the qualifying facility.

NOW, THE COMMISSION, after consideration of the evidence presented in this proceeding, is of the opinion and finds:

(1) That the documents filed in Case Nos. PUE800082 and PUE800083 should be incorporated into the record of this proceeding;

(2) That each Qualifying Facility ("QF") with a design capacity exceeding 100 kw should negotiate the terms of its sale of electricity with Company and that the Commission will stand ready to arbitrate in the event that an agreement cannot be reached;

(3) That, in view of the cost of the facilities required for cogeneration, we believe Company's original proposal for assessing a monthly charge for the eventual replacement of interconnection facilities is consistent with the goal of encouraging cogeneration and, limited solely to that specific type of facilities, Vepco's proposed monthly assessment should be approved;

(4) That Company's proposed tariff Schedule 19 is a just and reasonable method of regulating the purchase by Company of electrical energy from qualifying cogenerators and small power producers operating facilities with design capacities of 100 kw or less; and,

(5) That the subject matter of proposed tariff Schedules 10 and 12 and of proposed paragraphs "C" and

"D" of Rider I are covered by tariff Schedule 19 or concern qualifying facilities with a design capacity exceeding 100 kw.

Accordingly, IT IS ORDERED:

(1) That Case Nos. PUE800082 and PUE800083 be, and hereby are, consolidated with the instant proceeding and all documents filed in Case Nos. PUE800082 and PUE800083 be transferred accordingly;

(2) That Company's tariff Schedule 19 be, and hereby is, approved for service rendered on and after the date of this order;

(3) That Company shall file the following data with the Commission on or before March 1 of each year (such data to cover the 12 months ending the previous December 31);

The name and location of each QF interconnected with Company;

The design capacity of each QF;

The amount of energy purchased from each QF;

The amount of energy sold to each QF;

Copies of any contracts entered into between Company and QFs;

Avoided costs data of the type required by 18 CFR § 292.302;

(4) That, there being nothing further to come before the Commission, the case be removed from the docket and the papers placed in the file for ended causes.

APPENDIX M

Final Order and Order Denying Petition for Reconsideration of the Virginia State Corporation Commission (November 15, 1985; December 6, 1985)

Case No. PUE830067
November 15, 1985

APPLICATION OF
VIRGINIA ELECTRIC AND POWER COMPANY

To revise Rate Schedule 19—Power Purchases from Cogeneration and Small Power Production Qualifying Facilities

FINAL ORDER

The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted by Congress to encourage conservation and efficient generation of electricity. Title II of that Act required the Federal Energy Regulatory Commission (FERC) to promulgate rules necessary to encourage cogeneration and small power production. As the United States Supreme Court observed in Federal Energy Regulatory Commission v. Mississippi, 456 U.S. 742, 72 L. Ed.2d 532, 102 S. Ct. 2126 (1982) and American Paper Institute, Inc. v. American Electric Power Service Corporation, 461 U.S. 402, 76 L. Ed.2d 22, 103 S. Ct. 1921 (1983), Congress believed that the development of cogeneration and small power production would reduce the demand for traditional fossil fuels. The FERC promulgated the required rules and thereby provided each state regulatory body a general framework within which the state authority was required to implement the PURPA mandate. The FERC rules afforded state commissions wide latitude in implementing the statutory requirements. A state commission could issue regulations,

resolve disputes on a case by case basis, or take any other action which was reasonably designed to give effect to the FERC regulations and PURPA.

As part of that general framework, the FERC provided that electric utilities must pay new qualifying facilities (QFs) an amount equal to the full avoided costs for the power sold by the QF. Although that standard appears clear enough, the calculation of those avoided costs can be the source of significant controversy, as demonstrated by this proceeding.

In Virginia the Commission determined that it was most appropriate to implement PURPA and the FERC regulations for each utility on a company by company basis. The Commission further determined that any QF with a design capacity exceeding 100 kw would very probably be a large concern with sufficient bargaining power to effectively negotiate the terms of its sale of electricity to the utility company. Therefore, the Commission determined that the terms, conditions and payment levels approved by the Commission for each utility should be applicable only to small QFs with a design capacity of 100 kw or less. The Commission, however, did offer to arbitrate whenever the large qualifying facility and the electric utility could not reach an agreement.

On January 11, 1983, in Case No. PUE800102, the Commission approved initial energy and capacity payments which it determined were reasonable for Virginia Electric and Power Company (Vepco) to pay small qualifying cogenerators and small power producers selling power to Vepco.

By letter dated October 27, 1983, Vepco was directed to update and file new rates which it proposed to pay QFs for purchased power based on current projections of its avoided costs. On December 1, 1983, Vepco filed its application and supporting testimony requesting a reduction in the energy and capacity payments it was re-

quired to pay to QFs. Vepco also requested approval of standard contracts for new QFs with a design capacity of less than 1,000 kw and a second standard contract for QFs with a design capacity of over 1,000 kw, as well as modification of the applicability of Vepco's Schedule 19 which currently reflects the terms, conditions, and avoided cost rates applicable to QFs with a design capacity of less than 100 kw.

Pursuant to the Commission's direction, Vepco revised its application on January 30, 1984, to base its proposed energy payments on projected avoided energy costs for the period of April 1, 1984, through March 31, 1985, and to base capacity payments on 1984 dollars, rather than 1983 dollars. Vepco's revised proposal was for a reduction in its time differentiated energy payment from 5.203 cents per on-peak kwh to 3.968 cents per on-peak kwh. It proposed to purchase non-time differentiated power on the same basis as off-peak power, 2.304 cents per kwh, a reduction from 3.132 cents per off-peak kwh. Vepco also proposed to change capacity payments. Prior to its filing, its capacity payments were .803 cents per on-peak kwh of dependable capacity for purchases with a contract term of less than five years and 1.253 cents per on-peak kwh for purchases with a contract term of five years or longer. Vepco proposed a graduated payment plan for capacity equal to $32.50 per kw per year or .833 cents per on-peak kwh for short term purchases with contract terms of nine years or less. For long term purchases with contract terms over nine years Vepco proposed to make capacity payments equal to the average of $32.50 per kw for each of the first nine years and $78.25 per kw for each additional year, with each year adjusted for the change in the GNP implicit price deflator during the previous year.

Vepco subsequently amended its proposal. By the conclusion of the hearing Vepco proposed on-peak energy payments of 4.109 cents per kwh and off-peak energy

payments of 2.477 cents per kwh. Its final proposal for capacity payments remained the same as described above.

Beginning on June 11, 1984, a public hearing before a Hearing Examiner was held. Counsel entering an appearance in this proceeding were: Richard D. Gary, Esquire, and Laurence Skinner, Esquire, for Vepco; Edward L. Flippen, Esquire, and John Carrara, Esquire, for Stone Container Corporation and Westvaco Corporation, Protestants; Eric M. Page, Esquire, Glenn J. Berger, Esquire, and Leslie J. Goldman, Esquire, for Union Camp Corporation, Protestant; A. C. Epps, Esquire, for the Virginia Committee for Fair Utility Rates, Protestant; Charles G. Flinn, Esquire, for Arlington County, Protestant; Cyril D. Calley, Esquire, for the City of Alexandria, Protestant; Daniel I. Prywes, Esquire, and Mark T. Gergen, Esquire, for Philip Morris, Inc., Protestant; Jim L. Chinn, Esquire, for the City of Richmond, Protestant; James C. Dimitri, Esquire, on behalf of the Office of the Attorney General, Division of Consumer Counsel; and Kenworth E. Lion, Jr., Esquire, Counsel to the Staff. Eighteen public interveners appeared and made statements.

On August 9, 1985, Senior Hearing Examiner Russell W. Cunningham issued his report and recommendations in this proceeding.

Parties' Exceptions and Comments to the Hearing Examiner's Report were filed on September 6, 1985.

The development of cogeneration and small power production in Virginia must be encouraged, and this Commission intends to do so. Such development has this Commission's full support for a number of persuasive reasons. Cogenerators can use fuel to produce steam for both their traditional industrial processes and to produce electricity. The extra cost to generate such electricity is obviously lower than the cost of generating electricity alone. Cogeneration is an economic and efficient use of

this nation's energy resources. It is also in the national public interest to decrease our reliance on scarce fossil fuels.

Similarly, a small power producer can make electricity from renewable resources. In Virginia, we have seen a particular interest in the use of water, wood chips, and waste resources. Again, this type of electric generation is economic and results in decreased reliance on traditional fuels.

There are many other direct and indirect benefits which inure to utilities such as Vepco, the ratepayer and the public at large from the encouragement of cogeneration and small power production. Such generation may enable the utility to defer investment in large generation units and thereby minimize the burden of utility financing. Moreover, small additional increments of power supply may also help the utilities more closely match their supply with the demand for electricity. Further, many small decentralized units will help insulate the utility and its ratepayers from major disruptive outages as may occur with a few large centralized generating units. Clearly, cogeneration and small power production are in the public interest.

The record amassed in this case is extensive. Numerous complex issues were raised and addressed. After reviewing the entire record, we have disposed of those issues as set out in the findings and conclusions in the remainder of this order. We believe the results we have reached here will make it clear that cogeneration and small power production facilities are welcome in Virginia and that this Commission fully supports the underlying concepts and intends to see that the development of those facilities is strongly encouraged in this state.

For example, we concur with the Hearing Examiner's recommendation that the use of standard contracts for both large and small QFs is not in the public interest and should be rejected. It was emphasized at the hear-

ing that each QF has unique characteristics which could make certain contract terms more important to one facility than another. Therefore, it is important for the Commission to maintain the requisite flexibility to allow larger QFs to negotiate the terms of their contracts to sell power to Vepco. Applicability of Vepco's Schedule 19 will therefore continue to be limited to small QFs with a design capacity of 100 kw or less. Standard contracts will not be approved for large QFs.

We disagree with the Hearing Examiner's recommendation that cogeneration contracts filed with the Commission should be held in camera. In orders filed on April 12 and April 22, 1983, in Case No. PUE830017, we denied a request by Vepco to make QF contracts unavailable to the public. We have re-examined our previous holding in light of the arguments received herein and continue to believe that it is in the public interest for QF contracts to be open for inspection by interested persons. We, therefore, adhere to our previous ruling.

In addition, for the purpose of Schedule 19 and for application to the small QFs covered thereby, "old" QFs should continue to receive full avoided cost payments. However, once again Vepco may negotiate other terms or payments with large QFs constructed prior to the enactment of PURPA.

In its application, Vepco proposed a new provision to Schedule 19 which would require the installation of telemetering equipment on all cogeneration and small power production facilities. It is unreasonable to require such equipment to be installed on the small facilities covered by Schedule 19. Vepco's proposal to incorporate that requirement is therefore rejected.

One of the most highly litigated issues in this proceeding was the appropriate methodology for determining Vepco's avoided energy costs. More particularly, several Protestants in this case raised serious questions on the use, input to and the accuracy of PROMOD. Vepco's

production costing simulation computer model. It is a well-established principle that a utility carries the burden of proving that the relief it requests in regulatory proceedings is reasonable and justified. In this case, Vepco's proposed rates were based to a large extent on the use of PROMOD, and we agree with the Protestants that such a computer program must be shown to be appropriate for the use to which it is put. The program should also be shown to produce valid results, based on suitable and reasonable inputs and assumptions, before it can form the basis of proof in a proceeding such as this. This record, however, reveals significant problems of proof with regard to this computer model which played such a principal role in deriving avoided energy costs. Vepco apparently input actual historical data in only one PROMOD run, which assumed QFs to be present on the system, in an attempt to validate the avoided energy cost calculations. Such minimal efforts do not constitute adequate validation. The case for the use of PROMOD in the determination of acceptability reliable avoided costs has not yet been established to the satisfaction of the Commission.

The Commission believes that a cooperative effort among Staff, Vepco and QFs can best develop the most appropriate method of determining avoided costs. This is particularly true inasmuch as we realize that, whatever the Commission's pronouncements on the subject, the matter will continue to remain controversial until the parties most immediately concerned, the utilities and the QFs, become satisfied that the process is reasonable and produces fair results. However, too much time has already elapsed in this proceeding to allow such a task force to conduct its work prior to our determination here of the reasonable level of payments which should be paid to QFs. Nevertheless, such a task force should be established and the consensus of the group presented in Vepco's next case. We are hopeful that the task force will be able to develop and propose, among other things, an

appropriate methodology for determining avoided energy costs which will be satisfactory to all. This methodology may or may not entail the continued use of PROMOD; however, for the purposes of this case there is no alternative to PROMOD offered in the record. The avoided energy cost calculations of 4.109 cents per on-peak kwh and 2.477 cents per off-peak kwh will therefore be used as the starting point in the development of energy payments for this proceeding. Vepco must, however, understand that our use of PROMOD for this case does not mean that the Commission finds that it has been sufficiently validated or that it represents the best approach to the derivation of avoided energy payments to QFs.

It is true that PROMOD has been used for years in Vepco fuel factor proceedings. However, there is a correction mechanism in the Fuel Factor to prevent over- or under-recovery by the utility. No such mechanism is included in the calculation of payments to QFs. That fact, alone, is sufficient reason why the inputs and calculations of PROMOD should be more carefully reviewed in cogeneration proceedings, and it is particularly important that the validity of computer models used in the process be clearly demonstrated.

Moreover, the Commission notes the discrepancy between the energy payments to QFs which Vepco proposed for the 1984-85 Fuel Factor and those calculated in this case. Both the fuel factor and the current projections of QF avoided cost rates were filed with the Commission on the same day. It would appear that the same inputs and data should be used in both proceedings. No explanation for the discrepancy was offered by Vepco. Hereafter, Vepco is expected to make consistent calculations in both the fuel factor and QF filings.

The FERC regulations very clearly provide the QF with the option of selling electricity to the utility at an avoided cost rate based on projections of avoided costs at the time the contract is executed or at the time the

power is actually delivered. Such an option is not only reasonable, but it is mandated by the FERC rules. To facilitate the availability of this option, it shall be incorporated into Schedule 19. To avoid encumbering the Schedule with all the alternative sets of projections available, Schedule 19, itself, should simply state that these two options exist, and the projected energy cost for contract terms of 5, 10, 15, 20, 25 and 30 years should be filed as an attachment to Schedule 19.

Vepco proposed to pay the off-peak energy rate for non-time differentiated purchases. Continued use of the weighted average costs calculated using on-peak and off-peak energy rates more accurately reflects the avoided cost of non-time differentiated power purchases from QFs. Therefore, Vepco's proposal is rejected and the starting point for calculating the appropriate payment for non-time differentiated purchases should be 3.204 cents per kwh.

Operating and maintenance costs should be included in the avoided energy cost calculation. Although average O&M costs may provide the easiest approach to the derivation of that energy related cost, the development of incremental O&M costs which was proposed by Protestant Union Camp more closely comports with the goal of developing payments based on the costs which would have been incurred by Vepco but for the presence of QFs on its system. That calculation in the proceeding must be updated, however, and the appropriate additional factor for avoided O&M costs in this case is 0.2131 cents per kwh.[1]

Amounts related to transmission line losses should also be factored into avoided energy cost calculations. It would be preferable to calculate this adjustment on a facility by facility basis, but for the purposes of Schedule

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[1] See attached Schedule A for derivation of avoided O&M costs factor.

19 we will approve continued use of average transmission line losses. The appropriate component to be added to Schedule 19 energy payments is 0.275 cents per on-peak kwh and 0.166 cents per off-peak kwh.[2] For non-time differentiated purchases the weighted average of 0.214 cents per kwh should be factored into the total payment level.

In its application, Vepco proposed several changes to its capacity payments. It sought to increase the contract term necessary to receive long term capacity payments from five years to nine years. However, the record indicates that Vepco can alter its generation mix within a five year period; therefore, the five year term will be retained. Long term capacity payments will continue to be available to any QF which commits to a contract term of five years or more.

Vepco further proposed a change in the methodology of calculating avoided capacity payments. The existing methodology uses projected booked capacity costs to derive the capacity payments. Vepco's proposed short term capacity payments were based on six months of the Hoosier purchased power related costs. It proposed long term capacity payments based on a 750 MW coal fired generating unit projected to come on line in 1992. Too many problems with Vepco's new methodology were left unanswered in this proceeding. Therefore, we will adjust the previously approved capacity payment levels, which were based on 1981 data, for the change in GNP implicit price deflator from 1981 to 1984.

We further conclude that it is unreasonable to hold the QF to a reliability standard which Vepco itself has not come close to achieving. The Hearing Examiner's recommendation to compute the per kwh capacity payment to

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[2] The transmission line loss factor was calculated in accord with Staff's recommendation in this case, by multiplying the on-peak and off-peak energy payments of 4.109 cents and 2.477 cents, respectively, by 6.682%.

QFs by multiplying the dependable capacity rating by the average availability of Vepco's own generation is reasonable and will be adopted. The reliability multiplier which would require QFs to be available with the same degree of reliability as Vepco's own generation in order to receive full capacity payments is 1.25. As thus calculated, capacity payments available to QFs under Schedule 19 will be 1.281 cents per on-peak kwh for short term purchases and 2.00 cents per on-peak kwh for long term purchases.

At this point we have discussed and resolved several issues which must be taken into account in developing avoided cost payments to QFs. Many of these issues, such as avoided energy and capacity costs, and adjustments for operation and maintenance and transmission loss factors, are costs internalized by the utility, and can be studied using the characteristics of that utility system, projections of its future operations, and the like. Other factors which make cogeneration and small power production facilities beneficial and in the public interest are more intangible however, and the associated costs which can be avoided are societal and environmental in nature. Such costs are not borne directly by the utility but by the public as a whole.

We have previously alluded to a number of these factors, and now note several that are required to be taken into account by the FERC rules. One is a reduction in the use of fossil fuels,[3] which saves money, conserves scarce resources, and lessens environmental pollution. Another is the possible deferral of major capacity additions by utilities,[4] which not only is financially advantageous to the utility but also conserves the real estate and other material and human resources which go into building and operating a major plant. Also of importance are

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[3] 18 CFR § 292.304(e)(3).

[4] Ibid.

the shorter construction lead times and smaller additions to capacity which are possible with QFs.[5] The inability to respond quickly to small changes in demand caused by the long planning and construction times for major utility plants imposes many costs on society which are not paid by the utility, but which should be addressed in fixing avoided cost rates.

There are also enormous benefits to system reliability inherent in the prospect of having many small dispersed QFs throughout a state or region supplying the same amount of power as a single large utility plant, but without the catastrophic results possible should that single plant suffer an outage.[6]

It is thus important that factors such as the foregoing be considered in developing avoided cost rates. It is not to be expected, however, that such intangible benefits can be priced with mathematical precision and, therefore, it is not surprising that no attempt was made by the parties in this case to quantify their value. This fact does not relieve the Commission of its responsibility under the law to give reasonable weight to these matters. This task requires the exercise of our judgment and discretion, bearing in mind the mandate of PURPA that cogeneration and small power production is to be encouraged. We believe that the best way to accomplish this in the present case is to increase the avoided energy costs payments for both on- and off-peak periods by 15%. Thus, the rates for energy under Schedule 19 will be 4.725 cents per on-peak kwh, 2.849 cents per off-peak kwh and 3.685 cents per kwh for non-time differentiated purchases.

Above all, it must be emphasized that we recognize the unique characteristics of each QF. Consequently, we continue to encourage Vepco to negotiate contracts with each QF, giving due consideration to those characteristics

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[5] 18 CFR § 292.304(e)(2)(vii).

[6] 18 CFR § 292.304(e)(2)(vi) Sch.

and the potential benefits which can result from cogeneration and small power production. As always, the Commisison stands ready to arbitrate specific contractual differences between the parties.

NOW, THE COMMISSION, upon consideration of the record in this proceeding, the Hearing Examiner's Report, the exceptions and comments filed by the parties to that Report, and the applicable law, is of the opinion and finds:

(1) That Vepco's proposal for standard contracts for all QFs is not in the public interest and is rejected;

(2) That all contracts executed by Vepco with QFs shall continue to be filed with the Commission and shall remain available for public inspection;

(3) That it is reasonable for Schedule 19 to remain applicable to both old and new QFs with a design capacity of 100 kw or less;

(4) That the proposal to incorporate a requirement for telemetering equipment as a provision in Schedule 19 is rejected;

(5) That Schedule 19 must be revised to provide QFs the option of contracting for payments based on projected avoided energy costs either at the time the contract is executed or at the time power is delivered;

(6) That is reasonable to use PROMOD to calculate total avoided production costs to develop a portion of payments for purposes of this proceeding. However, it is in the best interests of Vepco, QFs and the ratepayers that a cooperative task force be formed to investigate and make recommendations to the Commission for the most appropriate methodology to calculate avoided costs in future proceedings;

(7) That, in recognition of the various intangible societal and environmental benefits of cogeneration and small power production, it is proper to increase Vepco's

final proposed avoided energy costs payments for both on- and off-peak periods under Schedule 19 by a factor of 15%;

(8) That Vepco's avoided energy costs, plus the intangible considerations discussed above, support energy payments, exclusive of the O&M costs adjustment and the transmission line loss adjustment, of 4.725 cents per on-peak kwh and 2.849 cents per off-peak kwh;

(9) That the weighted average rate of 3.685 cents per kwh calculated using both on-peak and off-peak energy rates reasonably reflects the avoided cost of a non-time differentiated purchase;

(10) That operating and maintenance costs and transmission line losses should be included in the calculation of energy payments for Schedule 19 purposes. The incremental system O&M cost is 0.2131 cents per kwh. Average transmission line losses shall also be applied to Schedule 19 energy payments. That additional component is 0.275 cents per on-peak kwh and 0.166 cents per off-peak kwh, or 0.214 cents per kwh for non-time differentiated purchases;

(11) That it is proper to offer long term capacity payments to a QF which executes a contract with a term in excess of five years;

(12) That it is not reasonable to require QFs to be available 100% of on-peak hours in order to receive full capacity payments. It is, however, reasonable to hold QFs to the same reliability standard at which Vepco operates;

(13) That under Schedule 19 capacity payments should be 1.281 cents per on-peak kwh for short term power purchases (less than five year contract terms) and 2.00 cents per on-peak kwh for long term purchases to be adjusted each year for the change in the GNP implicit price deflator during the previous year; and

(14) That Vepco has underpaid QFs during the interim period and should, therefore, make additional payments to QFs for the period from April 1, 1984 to the present.

ACCORDINGLY, IT IS ORDERED:

(1) That Vepco shall file its revised Schedule 19 on or before November 29, 1985, to be effective on April 1, 1984, in accordance with the above findings;

(2) That, on or before December 20, 1985, Vepco shall make additional payments, with interest, to compensate QFs for the underpayments made by the application of the interim rates which became effective for purchases from QFs on and after April 1, 1984, to the extent that the interim payments were less than the payments which would have been made by the application of the permanent rates to be filed in compliance with this order;

(3) That interest shall be computed from the date payment is due until the date additional payments are made at an average prime rate for each calendar quarter. The applicable average prime rate for each calendar quarter shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate values published in the Federal Reserve Bulletin, or in the Federal Reserve's "Selected Interest Rates" (Statistical Release G.13), for the three months of the preceding calendar quarter. The interest required to be paid shall be compounded quarterly;

(4) That, on or before December 30, 1985, Vepco shall file with the Commission's Staff a document showing that all additional payments have been properly made pursuant to this Final Order;

(5) That Staff from the Divisions of Energy Regulation and Economic Research and Development shall coordinate a task force of Vepco and QF representatives to develop an acceptable methodology for calculating avoided costs in the future; and

(6) That there appearing to be nothing further to come before the Commission in this proceeding, this case shall be removed from the docket and the papers placed in the file for ended causes.

Commissioner Elizabeth B. Lacy did not participate in this proceeding.

Schedule A

O & M COSTS FACTOR
DERIVATION

Resource	GWH	Percent	Average Variable O&M Cost cents per kwh	Average Variable O&M Cost cents per kwh
Nuclear	38.0	4.8%	0.0	0.0
Fossil	605.8	75.8	0.1480 [1]	0.1122
Combustion Turbines	27.4	3.4	2.968 [2]	0.1009
Other	127.8	16.0	0.0	0.0
Total	799.0	100%	3.115	0.2131

[1] $28,113,047 ÷ 18,995,854,000 kwh = .0014799 (.1480¢ per kwh)

[2] $1,164,652 ÷ 39,236,000 kwh = .02968 (2.968¢ per kwh)

Case No. PUE830067
December 6, 1985

APPLICATION OF
VIRGINIA ELECTRIC AND POWER COMPANY

To revise Rate Schedule 19—Power Purchases from Cogeneration and Small Power Production Qualifying Facilities

ORDER DENYING PETITION
FOR RECONSIDERATION

On November 15, 1985, the Commission issued its Final Order in this case which, among other things, revised the rates Virginia Electric and Power Company (Vepco or Company) is required to pay qualifying cogeneration and small power production facilities under Schedule 19 of its tariffs.

On November 25, 1985, Vepco filed a Petition for Reconsideration of that Final Order. Vepco requested reconsideration of findings made on the following issues: the necessity to offer long term energy rates, the required level of energy rate payments, and the appropriateness of the application of a reliability multiplier to determine reasonable capacity payments. Vepco further requested the Commission to make clear that the Commission is not required to pay QFs more than Company's avoided capacity costs per kw if the QF unit is more reliable than Company's own generation. Another issue raised in the Petition focuses on the appropriateness of the use of PROMOD for the determination of voided energy costs. Finally, Vepco sought reconsideration of the method used in deriving the adjustment to Schedule 19 for avoided line losses.

In view of the importance of this case, we have very carefully considered the points raised in Vepco's Petition for Reconsideration. After again reviewing the record,

we have concluded that there is no reason to modify our previous decision in the case, except for one point to be mentioned below.

Our examination of Vepco's Petition, however, does lead us to believe that the Commission may have misinterpreted the basic thrust and intention of the subject order. We, therefore, find it desirable to revisit and amplify certain aspects of that order.

First, and foremost, we did not hold, nor did we intend to suggest, that any QF is to be paid more than full avoided costs, for any reason. Company's contrary impressions are in error.

It is true, of course, that the final payments proposed by Vepco to capture full avoided costs were not adopted by the Commission; we decided that higher rate levels were necessary to meet that standard. In reaching that decision, we were careful, as mentioned in our order, to take into account every facet of avoided costs specified in the FERC regulations. However, the mere fact that the Company's position was rejected does not validate, for example, the argument in its Petition that the required payments to QFs will thus be at "115% of full avoided costs." [1]

In the first place, Vepco was not the only party in the case to suggest certain rate levels to meet the federal standards. Stone Container witness Shanker, for example, testified that the calculation of avoided energy costs should include certain adjustments which would result in an energy payment for on-peak periods in the range of 5.4 to 5.5 cents per kwh, disregarding additions for transmission line losses and operation and maintenance expenses. Also, as we noted in the November 15th order, Vepco's originally proposed rates in this case differed from its projected rates which were filed the same day

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[1] Vepco, Petition for Reconsideration, p. 6.

in its 1984-85 Fuel Factor proceeding. Those Fuel Factor projections for on- peak and off-peak avoided energy costs were 4.67 and 2.62 cents per kwh, respectively. The level of avoided energy cost payments, prior to adjustment for line losses and O&M expenses, which the Commission adopted in this case—4.725 and 2.849 cents per kwh, on-peak and off-peak—thus fit well within the range of rates proposed in this record, and only slightly exceed Vepco's own numbers from its Fuel Factor filing.

It bears repeating that the Commission's holdings on rate levels were intended to match, not exceed, full avoided costs. Further, the Commisison fully recognizes that the methodology it chose in this proceeding to satisfy that standard may well not be the ultimate answer to the problem. We fully expect to reexamine this methodology in future cases. As we said in our order, it is also expected that the parties most concerned with this process, the utility and the QFs, will conduct immediate and extensive negotiations, in conjunction with our Staff, which will produce a more refined and improved method for capturing every aspect of full avoided costs. It is anticipated that the results of these negotiations will be acceptable to all parties and, when presented to the Commission, can be determined to be in the public interest and, thus, approved. We believe the foregoing to be the best way to eliminate the substantial controversy and uncertainty over the methodologies, rate levels, payment options, etc., which permeated this case.

The Commission also believes, however, that the methodology adopted in our recent order was reasonable and fully justified, and that it will serve well until a replacement is developed and approved. The Commission looks forward to considering other ways of meeting the federal mandate under which it operates in this area.

We noted above a need for clarifying one point in the order of November 15. It relates to Vepco's concern

(11) What rights, if any, should Virginia Power have to purchase the Facility?

WHEREFORE, UCS petitions the Commission to institute an arbitration proceeding.

Respectfully submitted,

ULTRA COGEN SYSTEMS, INC.

By /s/ Edward L. Flippen
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Dated: November 12, 1987

(Appendices Omitted)

APPENDIX C

Opinion and Final Order of the Virginia State Corporation (February 13, 1990)

Re Doswell Limited Partnership

Case No. PUE890068

Virginia State Corporation Commission
February 13, 1990

Opinion, Harwood, Commissioner:

OPINION AND FINAL ORDER

On September 25, 1989, Doswell Limited Partnership ("Doswell"), an independent power producer ("IPP"), filed an application with supporting prepared testimony and exhibits requesting the Commission's approval of Doswell's proposed construction of a 650 megawatt ("MW") combined-cycle generating plant to be located in Hanover County, Virginia. The applicant sought a certificate of public convenience and necessity, pursuant to Virginia Code § 56-265.2, and pursuant to Virginia Code § 56-234.3 which requires the company to satisfy the Commission following a public hearing, that ". . . the proposed improvements are necessary to enable the public utility to furnish reasonably adequate service and facilities at reasonable and just rates."

On October 3, 1989, the Commission issued an order directing Doswell to publish notice of its application and setting a procedural schedule. The application raises issues of first impression for this Commission concerning our jurisdiction over IPPs. Accordingly, we identified certain legal issues to be briefed

by Doswell and the Commission Staff, which briefs were filed on November 3, 1989. The required public hearing was held on December 7, 1989.

At the outset, it must be observed that Doswell has no certificated service territory and seeks none. As it stands, Doswell has no service obligations to Virginia customers. Its generating output will be sold exclusively to the Virginia Electric and Power Company ("Virginia Power") for resale. For this reason it is clear that the Commission must analyze the application in terms of Virginia Power's duty to provide reliable service to its customers at "reasonable and just rates."

Although this is the first application filed with the Commission for approval of an IPP facility, third-party generation is not new to us. Cogeneration and small power production have been steadily growing in the Commonwealth since the passage of the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 2601 *et seq.* (1978) ("PURPA"). We have encouraged that development primarily because of the conservation objectives underlying PURPA. Facilities qualifying for construction under PURPA do not file with this Commission for construction and operating authority. IPPs, however, such as Doswell, are not afforded federal exemption from state regulation.

I. LIMITED PARTNERSHIP ORGANIZATION

Doswell is a limited partnership organized under the laws of the Commonwealth of Virginia. The sole general partner of the limited partnership is Doswell I, Inc., a Delaware corporation and a wholly-owned subsidiary of Diamond Energy, Inc. ("Diamond"). Diamond is a wholly-owned subsidiary of Mitsubishi Corporation. A second wholly-owned subsidiary of Diamond, Doswell II, Inc., is the sole limited partner of the limited partnership. Doswell II, Inc., is also a Delaware corporation. Doswell intends to sell limited partnership interests to a number of different entities and

eventually remove Doswell II, Inc. as a limited partner. Doswell, as a successor in interest to Intercontinental Energy Corporation ("IEC"), is a party to two power purchase and operating agreements ("the agreements"), each dated June 22, 1987, with Virginia Power. At the hearing, Doswell indicated that it was in the process of negotiating changes to several provisions in the agreements.

The Virginia Constitution provides that "[n]o foreign corporation shall be authorized to carry on in this Commonwealth the business of, or exercise any of the powers or functions of a public service enterprise, . . . " Virginia Constitution Art. IX § 5. Virginia Code § 13.1-620(E) prohibits the Commission from issuing a certificate of incorporation "[i]f one or more of the purposes set forth in the articles of incorporation is to own, manage or control any plant or equipment within the Commonwealth . . . for the production of heat, light, power" unless the articles, ". . . expressly state that the corporation is to conduct business as a public service company." Consequently, a domestic public service corporation is the only *corporate entity* which can engage in a public utility activity in Virginia. Doswell, however, is not organized as a corporation, as are most public utilities in Virginia. It is a Virginia limited partnership, and the definitions of "company" in Virginia Code § 56-265.1(a) and "public utility" in Virginia Code § 56-265.1(b) explicitly permit partnerships to hold certificates of public convenience and necessity.

It is our opinion that the limited partnership in this case should be treated as a separate entity for purposes of the certification and approvals which it seeks. Under the common law aggregate rule, partnerships were not treated as legal entities apart from the individual partners. However, Virginia has adopted the Uniform Limited Partnership and Uniform Partnership Acts which recognize a partnership as a legal entity separate and apart from its partners. Virginia Code §§ 50-73.1, *et seq.* and 50-1 *et seq.* Notably, a partnership can hold title to property in its own name

and limit a partner's rights to possession of that property. Virginia Code §§ 50-8 and 50.25. Those property rights are analogous to a certificate of public convenience and necessity, which the Virginia Supreme Court has held to be a valuable property right. *Culpeper v. Virginia Electric and Power Company,* 215 Va. 189, 207 S.E.2d 864 (1974). The Virginia Code grants partnerships the right to carry on any trade or business as a separate legal entity, apart from the partners. Virginia Code §§ 50-6 and 50-73.9. In the course of conducting a business, a partnership can sue and be sued in its own name without joinder of the partners. Virginia Code § 50-8.1.

A partnership is a separate legal entity under these partnership laws, and the Utility Facilities Act expressly recognizes the right of a partnership to function as a public utility. Consequently, we recognize Doswell as the public utility which will own the generating unit, and conclude that the general and limited partners need not incorporate as public service corporations. However, the present general partner, and all such future partners, that are charged with managing the project, may have information that is vital for the Commission's ongoing regulation of the operation of the Doswell facility. Accordingly, we shall impose certain requirements upon the general partners, which will be discussed below.

II. COMMISSION JURISDICTION

Doswell asserts that because it will sell only wholesale electricity to Virginia Power, its rates and services are governed by Part II, Sections 205, 206, and 207 of the Federal Power Act (16 U.S.C. §§ 824d-f). The Federal Power Act, 16 U.S.C. § 824(b) and § 824d, provides that such wholesale rates are exclusively governed by the Federal Energy Regulatory Commission ("FERC"). Under the Federal Supremacy Clause of the U.S. Constitution (Article VI, cl. 2), states are pre-empted from modifying the rates established by FERC. Yet, such pre-emption

does not otherwise remove Doswell from this Commission's statutory authority.

Upon reflection, we believe it unnecessary, and potentially dangerous, to seek to determine in this order the full extent of our jurisdiction over the applicant pertaining to problems or situations which are not before us nor likely identifiable; we do not render advisory opinions. It is sufficient to state that we consider our jurisdiction to be coextensive with that over all other Virginia electric utilities except to the extent pre-empted by federal law.

While we recognize that Doswell's rates, *i.e.*, its contract with Virginia Power, are subject to the jurisdiction of the FERC, we are not precluded from this initial evaluation and adjudication of the viability and appropriateness of the Doswell project. To the extent that the FERC jurisdiction is hereafter modified, terminated, or waived, we would expect to assert our jurisdiction to the full extent provided by state law. Further, a Doswell witness stated that he could not guarantee that Doswell's organizational structure would not change. If such a change occurs, it could trigger our jurisdiction.

As noted at the beginning of this order, the proposed facility is not one intended to supply electricity at retail to the customers of a utility possessing a certificated territory served by necessary transmission and distribution lines. Rather, since it serves only Virginia Power with wholesale power, the findings necessary under both Code §§ 56-265.2 and 56-234.3 must be established by evidence of need, costs, reliability, and preferable alternatives as those justifying elements relate to Virginia Power. The authority vested in the Commission by Virginia Code § 56-234.3 incorporates both licensing and rate aspects and Doswell itself recognizes that it is a "utility subject to the jurisdiction of the State Corporation Commission." Although our exercise of rate jurisdiction over Doswell is pre-empted, we do have certificate or licensing jurisdiction. That statute then is applicable to IPP projects as it relates to certificate matters. The fact that we do no

now expect to regulate Doswell's rates is not dispositive of our obvious need, and statutory duty, to conduct without reservation the investigation and overview contemplated by both of the foregoing code sections.

In this regard, Doswell is in a similar position to Old Dominion Electric Cooperative ("ODEC"), which is solely a wholesale power supplier to various retail cooperatives, in that ODEC is not subject to our rate jurisdiction as it relates to "sales of energy at wholesale,. . ." Va. Code § 56-231.12.[4]

Nevertheless, ODEC was recently brought before the Commission on a rule to show cause, Case No. PUE890045, when it became common knowledge that it had contracted for construction of a major generating plant without having filed for approval of that facility under Va. Code § 56-234.3. In fact, in earlier meetings with our Staff, ODEC had contended that such approval was unnecessary, since the Commission had no authority over wholesale rates. That argument was not pressed at the hearing on the rule, however, and soon thereafter, ODEC filed the appropriate application in Case No. PUE890051. That case culminated in our order of December 28, 1989, approving the new plant under the above provision. We see no reason not to apply the same statute to Doswell's proposals.

The Commission has a vital, ongoing interest in the construction and cost of the Doswell facility. Since we do regulate the services and rates of Virginia Power, it should be obvious that we have concerns with Doswell's proposal similar to those we would have if it were a Virginia Power proposal.

Inefficient, wasteful construction practices, procedures, designs, planning, etc., may have an adverse effect on Virginia ratepayers regardless of who the nominal builder/owner may be.

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[4] True, with ODEC, our lack of jurisdiction is due to state rather than federal law, contrary to Doswell, but otherwise the analogy is a close one.

By all means, our responsibilities under Virginia Code § 56-234.3 should be discharged to the fullest extent possible, consistent with federal pre-emption. This includes the possibility of the employment by the Commission, at Doswell's expense, of qualified persons to audit and investigate the project, as specifically provided in § 56-234.3.

We recognize that under Chapters 3 and 4 of Title 56, Code of Virginia, our duty to review and approve a utility's proposed issuance of securities and its agreements with affiliated interests is conditioned upon our coextensive duty to regulate the rates of that utility. In this case, although we have no immediate power to respond to Doswell's security issuances or to its dealings with affiliated interests, we have a vital concern in those subjects because of their potential involvement in future FERC proceedings of interest to this Commission.

Therefore, upon the granting of any certificate as herein requested, the certificate holder, together with all general partners of any partnership holding any interest in the certificate to the extent provided by statute, their successors and assigns, shall be subject to the applicable regulatory provisions of Title 56, 1950 Code of Virginia. Provided, however, for so long as the Commission is precluded by federal law from regulating the rates of the certificate holder, the certificate holder and its general partner shall be required only to file the following information:

(1) The issuance of stocks and stock certificates or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness and the creation of liens on any of the certificate holder's property within Virginia, as described in Virginia Code § 56-57, and amendments thereto, shall be accompanied by the filing with the Clerk of the Commission of a statement setting forth the amount, character, terms, and purposes of the stocks, stock certificates, or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness issued or assumed; and

(2) There shall be filed with the Clerk of the Commission copies of all contracts or arrangements described in Virginia Code § 56-77, and amendments thereto.

Our exercise of certificate jurisdiction will not impair FERC rate regulation. FERC's jurisdiction over licensing of power plants extends only to those entities enumerated under 16 U.S.C. § 797 *et seq.* Such entities do not include the type of facility Doswell proposes to construct. Moreover, Doswell recognized the proper exercise of jurisdiction by this Commission.

This Commission's exercise of jurisdiction over licensing and reporting requirements regarding an IPP is not pre-empted as long as our regulation does not frustrate federal law. *Hines v. Davidowitz,* 312 U.S. 52 (1941). With regard to the reporting requirements, 16 U.S.C. § 824(a) provides that federal regulation of electric utilities should not extend to those matters regulated by the states. It is specifically provided by 16 U.S.C. § 825(a) that the Act (16 U.S.C. §§ 791a *et seq.*) "shall not relieve any public utility from keeping any accounts, memoranda, or records which such public utility may be required to keep by or under authority of the laws of any state." In this case, clearly no conflict with federal law exists. Doswell has agreed to provide operating and technical records pursuant to our regulation. In addition, there is no indication in the record that state reporting requirements will frustrate federal law.

III. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

As a starting point in evaluating Doswell's application, the Staff considered the criteria established in Case No. PUE860058, *Application of Virginia Electric and Power Company* ("Chesterfield 7"), 1987 S.C.C. Ann. Rep. 262. In that Order, the Commission stated:

> Several factors must be demonstrated to the satisfaction of the Commission before it can properly approve any new construction. Among these factors are that the utility will have a need for additional power within the time frame contemplated; that its cost estimates, choice of technology, construction plans and proposed manner of carrying out the project are reasonable; and that there are no suitable alternatives to the proposed construction such as conservation and load management, upgrading existing units, or obtaining the necessary, power from resources other than the utility's own facilities.

Id. at 262.

The Staff determined that the above criteria did not fully cover the proposed construction. In order properly to review the project, the Staff found it necessary to examine the technical and financial viability of Doswell and the proposed project. The Commission is directed by statute to determine whether a certificate of public convenience and necessity is in the public interest. An IPP must show the need for the project and the technical and financial viability of the developer and the project to allow us to conclude that a certificate of public convenience and necessity is in the public interest.

The record reflects that Virginia Power has a need for capacity in the early 1990's. This need is increased by Virginia Power's recent change in its target reserve margin from 18.5% to 21%. The loss of capacity associated with the Doswell project would leave Virginia Power with a minimal allowance for further attrition of purchased power. Moreover, the witness from Virginia Power testified that the proposed Doswell facility is in an optimal location near a Virginia Power transmission line and the Richmond-Washington corridor.

The Staff reported that Doswell's anticipated contractual payments from Virginia Power, which are based on the avoided

costs of Chesterfield 7, are reasonable when compared to payments for power from similar projects. While Doswell will not receive revenues from steam sales (since it is not a cogeneration facility), it may experience certain economies of scale due to its size. There is no reason to believe that the costs of the project will become unreasonable because it is no longer a cogeneration facility.

Important to our determination of whether Doswell should receive Commission approval of its certificate request is whether Doswell has the technical and financial ability to construct and operate the plant. The record demonstrates that Doswell has made significant progress since it assumed the IEC contract in June 1989. It has issued a letter of intent to contract for construction of the facility on a turnkey basis with Fluor Daniel, Inc., a reputable engineering, construction, and planning contractor which has significant experience in the construction of power plants. Additionally, it has filed its contract with FERC to obtain approval of its contract rates with Virginia Power; it is gathering information to solicit an operations and maintenance contractor; and it has secured or is in the process of securing environmental permits. In fact, the project will use effluent from the Hanover County Waste Treatment Plant which will have a positive effect on the quality of water in the North Anna River system. Additionally, Diamond Energy is involved in the development of three other power projects. Its technical qualifications to undertake the project are adequate.

As to financial viability, the record shows that the developer, through the support of Mitsubishi Corporation, is a viable entity. This, of course, is important to investors. However, the nonrecourse nature of the contemplated financing requires us to consider the project's ability to be financed on a stand-alone basis. Doswell has issued its Project Information Memorandum outlining its need for financing, which it anticipates obtaining by March 1, 1990. Several major investors have expressed interest in financing the project. We are encouraged by the progress Doswell has made in obtaining financing, and we believe the record before us

provides reasonable assurance that the project can be adequately financed.

Doswell has taken steps to secure firm transportation and interruptible storage from Consolidated Natural Gas ("CNG") and has sought FERC approval. Furthermore, Doswell is also completing its negotiations with Virginia Natural Gas ("VNG") for a firm transportation and capacity contract.

Other aspects of Doswell's efforts also reflect that the project is viable. Doswell has provided security payments in advance of their due dates to Virginia Power, demonstrating its commitment to the project. Doswell is subject to the same liquidated damages as IEC for delays in meeting milestones set forth in the agreements. In order to secure timely performance, Doswell is negotiating provisions with its contractors for substantial liquidated damages for any delays or failures in performance.

The evidence reflects a need by Virginia Power for capacity in the early 1990's. The evidence further reflects that Doswell is assembling the necessary expertise to construct and operate the project, and that it is capable of attracting the necessary capital.

NOW, THE COMMISSION, upon consideration of the record in this proceeding and the applicable law, finds that:

(1) Doswell's proposed combined-cycle generating plant, to be located in Hanover County, Virginia, capable of producing approximately 650 MW of electricity, is necessary to meet Virginia Power's capacity needs. The Doswell facility should, therefore, be approved. Doswell shall keep this Commission apprised of changes, if any, to its purchased power agreements with Virginia Power.

(2) Doswell's construction of such facilities for use in public utility service is required by the public convenience and necessity,

pursuant to the provisions of Virginia Code § 56-234.3 and § 56-265.2.

(3) It is appropriate to impose certain conditions upon the issuance of the certificate in this case to assure that the Commission is kept apprised of the activities of the limited partnership and general partner. Accordingly,

IT IS ORDERED:

(1) That Doswell's proposed construction and operation of the combined-cycle facility is hereby approved under Virginia Code § 56-234.3, and a certificate of public convenience and necessity shall be issued therefor upon the filing of maps, pursuant to Virginia Code § 56-265.2, subject, however, to Doswell's filing with the Clerk of the Commission three (3) copies of the January 3, 1990, revised, executed power purchase and operating contract by and between Doswell and Virginia Power.

(2) That Doswell shall comply with any and all reporting requirements directed by the Commission related to the construction, operation, and technical aspects of the subject project, and shall not sell or transfer any of its utility assets or the certificate of public convenience and necessity without first seeking Commission approval;

(3) That the certificate holder, together with all general partners of any partnership holding any interest in the certificate to the extent provided by law, their successors and assigns, shall be subject to all of the regulatory provisions of Title 56 of the Virginia Code which are not pre-empted by federal law;

(4) Doswell shall file with the Clerk of the Commission, information, reports, and contracts as follows:

(a) The issuance of stocks and stock certificates or other evidences of interest or ownership, and bonds, notes, and other

evidences of indebtedness and the creation of liens on any of the certificate holder's property within Virginia, as described in Virginia Code § 56-57, and amendments thereto, shall be accompanied by the filing of a statement setting forth the amount, character, terms, and purposes of stocks, stock certificates, or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness issued or assumed;

(b) Copies of all contracts or arrangements, and amendments thereto, described in Virginia Code § 56-77;

(c) Three copies of any and all future contracts or arrangements, and amendments thereto, executed by and between Doswell and Virginia Power;

(d) Any and all information, reports, etc., related to its operations as requested by the Commission's Divisions of Energy Regulation, Economic Research and Development, and Accounting and Finance;

(e) The foregoing filing requirements shall be binding upon all successors and assigns of Doswell.

(5) And this cause is continued pending further Commission action.

ATTESTED COPIES hereof shall be sent to Laurence M. Hamric, Esquire, Robert E. Spicer, Jr., Esquire, Williams, Mullen, Christian and Dobbins, Two James Center, 1021 East Cary Street, P. O. Box 1320, Richmond, Virginia 23210-1320; and to the Commission's Divisions of Energy Regulation, Accounting and Finance, and Economic Research and Development.